Idaho Power Company

2002 Integrated Resource Plan

June 2002

Idaho Power Company

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Appendices:

Glossary of Acronyms

AEO – Annual Energy Outlook
AIR – Additional Information Requests
aMW – Average Megawatt
APS – Arizona Public Service
BPA – Bonneville Power Administration
CCCT – Combined-Cycle Combustion Turbine
CO_2 – Carbon Dioxide
CT – Combustion Turbine
DOE – Department of Energy
DG – Distributed Generation
DSM – Demand-Side Management
EA – Environmental Assessment
EIA – Energy Information Administration
FERC – Federal Energy Regulatory Commission
HP/IP – High Pressure/Intermediate Pressure
IOU – Investor-Owned Utility
IPC – Idaho Power Company
IPUC – Idaho Public Utilities Commission
IRP – Integrated Resource Plan
kV – Kilovolt
kWh – Kilowatt hour
LIWA – Low-Income Weatherization Assistance
MMBTU – Million British Thermal Units
MW – Megawatt
MWh – Megawatt hour
NEEA – Northwest Energy Efficiency Alliance
NWPPC – Northwest Power Planning Council
NOx – Nitrogen Oxides
NYMEX – New York Mercantile Exchange
OPUC – Oregon Public Utility Commission
PM&E – Protection, Mitigation and Enhancement
PV – Photovoltaic
QF – Qualifying Facility
RFP – Request for Proposal
RTO – Regional Transmission Organization
SCCT – Simple-Cycle Combustion Turbine
SO_2 – Sulfur Dioxide
SWIP – Southwest Intertie Project
TSP – Total Suspended Particulates
WACC – Weighted Average Cost of Capital
WEFA – Wharton Econometrics Forecast Associates
WECC – Western Electricity Coordinating Council

1. Integrated Resource Plan Summary

Introduction

The 2002 Integrated Resource Plan (IRP) is Idaho Power Company's (IPC or the Company) sixth resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC).

Prior to submission of the 2002 Integrated Resource Plan, two sets of public meetings were held. The first set of meetings solicited comments regarding water-planning criterion. Previous IRPs used median, or normal, stream flows for resource planning. The second set of public meetings followed the release of the draft version of the plan. In addition, written comments were solicited from the public at both stages.

Based on legislative actions in Oregon and Idaho, the 2002 Integrated Resource Plan assumes that during the planning period, from 2002 through 2011, Idaho Power will continue to be responsible for acquiring sufficient resources to serve all of its customers in its Idaho and Oregon certificated service areas and will continue to operate as a vertically-integrated electric utility. It is the intent that neither the Company nor its customers will be disadvantaged by decisions made in accordance with the 2002 Integrated Resource Plan.

The two primary goals of the 2002 Integrated Resource Plan are to:

1. Maintain Idaho Power's ability to reliably serve the growing demand for electricity within the service territory throughout the 10-year planning period.
2. Ensure that resources selected are cost-effective, low risk, and meet the increasing electrical energy demands of our customers.

The number of households in the Idaho Power Company service territory is expected to increase from around 310,000 today to nearly 380,000 by the end of the planning period in 2011. Population growth in Southern Idaho is an inescapable fact, and IPC will need physical resources to meet the electrical energy demands of the additional customers.

Idaho Power Company has an obligation to serve customer loads regardless of the water conditions that may occur. In light of public input to the planning process, IPC will emphasize a resource plan based upon a worse-than-median level of water. In the 2002 resource plan, IPC is emphasizing the 70th percentile water conditions and 70th percentile load conditions for resource planning. The water-planning criteria are discussed further in Chapter 4.

Risk Management

Idaho Power, in conjunction with the IPUC staff and interested customer groups, developed a risk management policy during 2001 to protect against severe movements in the Company's Power Cost Adjustment (PCA) balance. The risk management policy is primarily aimed at managing short-term market purchases and hedging strategies. The policy is intended to supplement the existing IRP process. In summary, the IRP will be the forum for making long-term resource decisions while the risk management policy will address the short-term resource decisions that arise as resources, loads, costs of service, market conditions, and weather vary.

Load Forecast

The 2002 Sales and Load Forecast includes three forecasts defining possible load conditions in the Idaho Power service territory during the 2002 through 2011 planning period.

The expected load forecast assumes median temperatures and median precipitation. Since actual loads can vary significantly dependent upon weather conditions, two alternative scenarios are also considered.

A 70^{th} percentile load forecast and 90^{th} percentile load forecast were prepared to address the weather risk and uncertainty inherent in forecasting loads. The 70^{th} percentile load assumes a level of monthly loads that are not likely to be exceeded 70 percent of the time. However, the 70^{th} percentile load forecast is expected to be exceeded 3 out of 10 years, or 30 percent of the time.

The 90^{th} percentile load forecast assumes monthly loads that are not likely to be exceeded 90 percent of the time. However, the 90^{th} percentile load forecast is expected to be exceeded in 1 out of 10 years, or 10 percent of the time.

The three forecasts are discussed further in Chapter 2 and in *Appendix B, 2002 Sales and Load Forecast*.

Resource Adequacy

In the Integrated Resource Plan modeling process, monthly demand and energy requirements from the 2002 *Sales and Load Forecast* are compared throughout the planning period against the generating capability of Idaho Power's power supply system. The comparison reveals Idaho Power's future need for additional capacity and energy resources.

Idaho Power has determined that existing resources, as described in Chapter 3, are likely to be insufficient to meet expected peak energy requirements under the 70^{th} percentile load and water conditions as early as 2003. Under the 70^{th} percentile water and load conditions, projected peak-hour loads may cause peak-hour transmission overloads from the Pacific Northwest presenting significant difficulties during the summers of 2003 and 2004. A combination of purchases from the east side, demand reduction programs, and temporary generation resources may be required to meet the projected summer peak-hour loads in 2003 and 2004.

Idaho Power Company recognizes that capacity constraints may present significant difficulties during the summer peak-hour conditions. IPC is addressing the potential difficulties (transmission overloads) projected for the summers of 2003 and beyond by pursuing several strategies that will enhance IPC's ability to serve projected loads without encountering transmission overloads from the Pacific Northwest. The strategies include:

1. Making firm purchases for the system (possibly sourced from areas other than the Pacific Northwest) while simultaneously making a non-firm off-system sale. This provides Idaho Power with the ability to interrupt the non-firm sale during critical peak-hour conditions.
2. Accelerating construction of the Brownlee to Oxbow Number 2 transmission line. The transmission deficiencies illustrated in Figure 17

assume the line is available summer of 2005. IPC is considering accelerating construction of the project to have the transmission available summer of 2004.

3. Idaho Power plans to continue investigating opportunities for cost-effective power exchanges as a method to manage projected surpluses and deficiencies. For example, the existing Montana exchange ends in December of 2003 – if an agreement similar to the current agreement was in place for summer 2004, the projected transmission overload from the Pacific Northwest projected for July would be reduced by 75 MW. Idaho Power has already contacted Northwestern Energy to discuss this opportunity.

In addition to the above strategies, Idaho Power has some short-term peaking capability at C.J. Strike, Bliss and Lower Salmon hydro plants that was not modeled in the monthly peak-hour surplus and deficiency, or the monthly peak-hour NW transmission deficit analyses. For these analyses, the three hydro plants were assumed to operate at the monthly average generation values. While the assumption simplifies the analysis, it also understates the important peaking capability of the projects.

The combined peaking capacity of these projects that is not accounted for in the above-mentioned analyses is approximately 100 MW for a 1-hour period. The dispatch of the plant capacity presents a complex modeling problem. Because of the complexity, the peaking capacity of the plants was not included in the resource model. However, Idaho Power Company intends to continue to use the peaking capacity of these plants in actual operations.

An additional 100 MW of term market purchases in June, July, November, and December to supplement the existing IPC resources are planned to meet the monthly average energy requirements through the summer of 2011.

Contingency Plans

The energy crisis of 2001 was a learning experience for Idaho Power. Several of the demand reduction programs developed during the energy crisis are considered to be active contingency plans, capable of being utilized again. One example is the Energy Exchange Program. The Energy Exchange Program enabled industrial customers to reduce load during certain hours in exchange for a payment from Idaho Power. While the program is currently inactive, the Energy Exchange Program could be reactivated on short notice, if necessary to respond to extreme conditions. Other demand reduction programs, such as the Irrigation Voluntary Load Reduction Program can be implemented on short notice if deemed necessary.

Garnet Delayed

In the 2000 Integrated Resource Plan, Idaho Power identified a need for additional generating resources located close to the Treasure Valley load center beginning in June of 2004. The identified need was the basis upon which Idaho Power issued the request for proposals (RFP), specifying an on-line date of June 1, 2004. The Garnet Energy LLC proposal was selected. A Power Purchase Agreement (PPA) between Idaho Power Company and Garnet Energy

LLC was negotiated and filed with the IPUC in December 2001. Section 4.4 of the PPA provides Idaho Power with an option to delay the guaranteed commercial operation date of the Garnet facility from the currently scheduled date of June 1, 2004 until June 1, 2005. The option exercise date was April 15, 2002.

To assess the cost, benefits and prudence of the PPA for Idaho Power rate-making purposes, the IPUC has scheduled technical hearings in Case No. IPC-E-01-42 for late July 2002. Considering the nature of Idaho Power's projected deficiencies for 2004, and the hearing schedule that commences after the Garnet delay option expires, Idaho Power has determined that it is prudent to delay the guaranteed commercial operation date of the Garnet facility until June 1, 2005.

Idaho Power's decision to delay the commercial operation date of the Garnet facility until June 1, 2005, will present several near-term challenges that will need to be addressed if a low-water and high-load condition occurs in 2004.

Future Resource Options

Beginning in June 2005, additional permanent resources will be required to meet Idaho Power Company's service territory load requirements. Idaho Power Company has three options available to meet the projected resource requirements:

1. Market purchases.
2. Generation and transmission resources.
3. Targeted demand-side management, targeted conservation measures, and pricing options.

Market Purchases

In the 2002 IRP, Idaho Power Company plans to use term market purchases from the Pacific Northwest throughout the planning period to supplement company resources in June, July, November, and December. The market purchases are placed in the resource plan in 100 MW increments. A term market purchase implies the purchase of a specific quantity of energy and capacity during a specific time period. Term market purchases are usually made prior to actual need and not during real-time system operation. Additionally, term market purchases are usually for longer time periods than are the hourly market purchases made during real-time system operations.

To not rely solely on long-term market purchases beyond 2004 was determined to be the optimum strategy because the delivery of increased market purchases from the Pacific Northwest would require substantial investments in additional transmission facilities to relieve constraints on Idaho Power's transmission system. However, term market purchases remain an important aspect of resource planning, allowing efficient timing of new resources as well as efficient use of existing resources. Transmission constraints are discussed more thoroughly in Chapter 3.

Generation and Transmission Resources

Generic generating resources using currently available technologies, including gas-fired and coal-fired thermal generation, renewable resource technologies such as hydropower, solar, geothermal, wind power, and generation from fuel cells, were considered as potential resources for inclusion in the 2002 Integrated Resource Plan. One of the technologies, a 100 or 200 MW simple-cycle gas-fired combustion turbine, was selected as the core supply-side resource for the third and fourth resource strategies in the final evaluation. A 64 MW upgrade to the Shoshone Falls plant is part of each resource strategy.

The 2002 Integrated Resource Plan incorporates the planned addition of a new 10-mile 230 kV transmission line between Brownlee and Oxbow. The Brownlee-Oxbow upgrade is expected to add 100 MW of transmission capacity. The transmission upgrade is planned to be in service by the fall of 2004.

Demand-Side Management and Targeted Conservation Measures

Due to the nature and timing of projected energy deficits and transmission overloads, conservation and demand-side measures must be carefully targeted to cost-effectively address the projected deficits. If the Idaho PUC approves the Company's proposed conservation rider, Idaho Power Company anticipates the addition of targeted demand-side management and targeted energy conservation programs.

Idaho Power Company plans to continue supporting regional and local conservation efforts, including NEEA. Participation in regional and local conservation efforts is contingent upon committed funding. Idaho Power Company will also proceed with plans to improve energy efficiency at other company facilities. Although not specifically identified in the Resource Strategies or the Near-Term Action Plan, Idaho Power will continue cost-effective incremental efficiency upgrades to existing generation facilities.

Four Resource Strategies Analyzed

Idaho Power's resource options for the planning period are described in Chapter 5. To meet the forecast loads in a cost-efficient manner throughout the 10-year planning period, IPC considered multiple resource acquisition strategies. The strategies included increased monthly energy and capacity purchases from the Pacific Northwest power market to meet seasonal deficiencies and the acquisition of additional generating capability from a portfolio of various generation technologies. Each resource strategy includes upgrading the Oxbow to Brownlee transmission path adding 100 MW of import capacity from the Pacific Northwest. Four strategies are being considered for final analysis and review:

1. The first resource strategy is a long-term limited-quantity market purchase strategy.
2. The second resource strategy is a combination of long-term market purchases of varying quantities and a 64 MW facility upgrade to the existing Shoshone Falls hydro plant.
3. The third resource strategy is a combination of short-term limited-quantity market purchases, the acquisition of 200 MW of peaking resources and a 64 MW facility upgrade at Shoshone Falls.
4. The fourth resource strategy is a combination of long-term limited-quantity market purchases, the acquisition of 100 MW of peaking resources and a 64 MW facility upgrade at Shoshone Falls.

The portfolio of resources is fully described in the Near-Term Action Plan (Chapter 7).

Near-Term Action Plan

Customer growth is the primary driving force behind Idaho Power Company's need for additional resources. Population growth throughout Southern

Idaho and, specifically, in the Treasure Valley requires additional measures to meet both peak and electrical energy needs.

Over the past 85 years, Idaho Power Company has developed a portfolio of generation resources. The Company believes that a blended approach based on a portfolio of options is the most cost-effective and least-risk method of addressing increasing energy demands of Idaho Power customers.

Because of the short duration of the forecast peak load conditions, Idaho Power has identified a resource strategy using both supply-side and demand-side measures. Idaho Power believes that the following plan, which outlines a balanced approach, has a high probability of being the least expensive for Idaho Power's customers.

The plan is based on Strategy 4, a combination of limited long-term market purchases and generation additions. The plan also calls for a transmission upgrade, along with an investigation into demand reduction measures suitable to address the short duration of projected peak-hour transmission overloads.

In summary, Idaho Power has identified six items to address the resource needs in the Near-Term Action Plan:

First, Idaho Power Company plans to continue to make seasonal market purchases of 100 aMW in the months of June, July, November and December throughout the planning period.

Second, Idaho Power Company plans to integrate demand-side measures, where economical, to address the short duration peaks of the system load.

Third, Idaho Power Company plans to solicit proposals and initiate the siting and permitting for approximately 100 MW of a utility-owned and operated peaking resource to be available beginning in 2005.

Fourth, assuming the Idaho PUC approves the Garnet Power Purchase Agreement, Idaho Power will purchase up to 250 MW of capacity and associated energy during periods of peak need beginning June 1, 2005.

Fifth, Idaho Power Company plans to proceed with the Brownlee to Oxbow transmission line, expecting the project to be in-service in 2005 and increasing the import capabilities from the Pacific Northwest.

Sixth, Idaho Power Company plans to proceed with the Shoshone Falls upgrade project, expecting the upgrade to be in-service in 2007.

Finally, Idaho Power Company plans to informally reassess the deficiencies that remain in 2008 though 2011 prior to 2004. The deficiencies will be formally assessed in the 2004 IRP.

Additional Steps

Idaho Power Company supports the Green Power Program. In order to meet the needs of customers desiring Green Energy, IPC has identified two specific near-term actions to be initiated during the next two years:

1. Idaho Power anticipates participating in several educational and demonstrational energy projects with a focus on green resources.
2. Idaho Power intends to dedicate up to $50,000 to explore the feasibility of constructing a pilot anaerobic digester project within the IPC service territory.

Idaho Power Company and the Commissions must agree on mechanisms that insure prompt recovery of prudent costs incurred for the pilot and demonstration projects.

Although not specifically identified in the Four Resource Strategies or in the Near-Term Action Plan, Idaho Power will continue to pursue cost-effective incremental upgrades at existing generation facilities.

Consistent with the final Risk Management Policy under review in Case No. IPC-E-01-16, Idaho Power Company will continue to use the short-term regional market to balance system load and generation, as well as take advantage of the long-term energy market to secure energy at reasonable prices.

Idaho Power Company continually works to improve the resource planning process. Idaho Power has recently made organizational changes to further improve integrated resource planning. The Company agrees with the IPUC that integrated resource planning will continue to be an important and ongoing activity at Idaho Power Company.

2. Load Forecast

Load Growth

Future demand for electricity by customers in Idaho Power Company's service territory is represented by three load forecasts, which reflect a range of load uncertainty. Table 1 summarizes the three forecasts of Idaho Power's annual total load growth during the planning period. The forecast 10-year average annual growth rate in the expected load forecast is 2.3 percent.

The expected load forecast represents the most probable projection of service territory load growth during the planning period. The forecast for total load growth is determined by summing the load forecasts for individual classes of service, as more particularly described in *Appendix B, 2002 Sales and Load Forecast*. For example, the expected total load growth of 2.3 percent is comprised of residential loads growth of 2.4 percent, commercial loads growth of 4.1 percent, irrigation loads growth of 0.4 percent, industrial loads growth of 2.4 percent, and additional firm loads growth of 2.2 percent.

Economic growth assumptions influence the individual customer-class forecasts. The number of households and employment projections, along with customer consumption patterns, are used to form load projections. Economic growth information for Idaho and its counties can be found in *Appendix A, 2002 Economic Forecast*.

The number of households in the State of Idaho is projected to grow at an annual average rate of 2.1 percent during the 10-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual county household forecasts. Growth in the number of households within the Idaho Power service territory, combined with reduced consumption per household, results in the previously mentioned 2.4 percent residential load growth rate.

The expected case load forecast assumes median temperatures and median precipitation; i.e., there is a 50 percent chance that loads will be higher or lower than the expected forecast loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation.

Since actual customer loads can vary significantly dependent upon weather conditions, two alternative scenarios were considered that address load variability due to weather. IPC has generated load forecasts for 70th percentile weather and 90th percentile weather. 70th percentile weather means that in seven out of 10 years, the load is expected to be less than the forecast and in three out of 10 years, the load is expected to exceed the forecast. 90th percentile load has a similar definition.

Cold winter days create high heating load. Hot, dry summers create both high-cooling and high-irrigation loads. In the winter, maximum load occurs with the highest recorded levels of heating degree days (HDD). In the summer, maximum load occurs with highest recorded levels of cooling and growing degree days (CDD and GDD). Heating degree days, cooling degree days, and growing degree days are used by IPC to quantify the weather and estimate a load forecast.

Table 1 Idaho Power Company

Range of Load Growth Forecasts
Average Megawatts

Forecast	2002	2004	2006	2008	2010	2012	Avg Annual Growth Rate
90^{th} Percentile Load	1,818	1,889	2,003	2,091	2,174	2,261	2.2%
70^{th} Percentile Load	1,753	1,821	1,933	2,018	2,099	2,183	2.2%
50^{th} Percentile Load (Expected or Median)	1,714	1,781	1,892	1,976	2,056	2,139	2.2%

For example, at the Boise Weather Service Office, the median number of HDD in December over the 1964-2000 time period is 1,039 HDD. The coldest December over the same time period was December 1995 when there were 1,619 HDD recorded at Boise.

For December, the 70^{th} percentile HDD is 1,079 HDD. The 70^{th} percentile value is likely to be exceeded in three out of 10 years on average. The 90^{th} percentile HDD is 1,278 HDD and is likely to be exceeded in one out of 10 years on average. Percentile estimation was used in each month throughout the year for the weather-sensitive customer classes - residential, commercial, and irrigation - to forecast load.

In the 70^{th} percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70^{th} percentile of HDD in winter and at the 70^{th} percentile of CDD in the summer. In the 70^{th} percentile irrigation load forecast, GDD were assumed at the 70^{th} percentile and precipitation was assumed to be at the 70th percentile, reflecting weather that is both hotter and drier than median weather. The 90^{th} percentile irrigation load forecast was similarly constructed using weather values measured at the 90^{th} percentile.

Idaho Power loads are highly dependent upon weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand that the probabilities associated with the load forecasts apply to any given month and that an extreme month may not necessarily be followed by another extreme month. In fact, a normal year likely contains extreme months as well as mild months.

Astaris Load

The Astaris elemental phosphorous plant temporarily ceased production at the end of 2001. Because of the change in its business situation, Astaris is expected to only require 10 MW per month for on-going maintenance. The 10 MW is included as a firm load requirement of Idaho Power. The Astaris special contract with Idaho Power will expire in March 2003, at which time Astaris is expected to become a Schedule 19 industrial customer. The Astaris contract allows for up to 240 MW of load and, until Astaris notifies Idaho Power of changes to the contract, IPC must consider the possibility of up to 240 MW of Astaris load. Until recently, Astaris had been IPC's largest individual customer.

Table 2 Idaho Power Company
Term Off-System Sales

Contract	Expiration	2002 Average Load
Washington City	June 2002	2 aMW
City of Weiser	December 2002	6 aMW
Utah Associated Municipal Power Systems	December 2003	40 aMW
City of Colton	May 2005	3 aMW
Raft River Rural Electric Cooperative	September 2006	6 aMW
Total Term Sales		*57 aMW*

Term Off-System Sales

Idaho Power currently has five term off-system sales contracts. Most of the five contracts were entered into in the late 1980s or early 1990s when Idaho Power had an energy and capacity surplus. The contracts, expiration dates, and average sales amounts are shown in Table 2.

The term sales contract with the City of Weiser is a full-requirements contract with Idaho Power. Under a full-requirements contract, Idaho Power is responsible for supplying the entire load of the City. The City of Weiser is located entirely within Idaho Power's load-control area.

A term sales contract with Raft River Rural Electric Cooperative Inc. was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commission of Nevada. Raft River Rural Electric Cooperative Inc. is the electric distribution utility serving Idaho Power's former customers in the State of Nevada. Idaho Power sold the transmission and distribution facilities, along with the rights-of-way that serve about 1,250 customers in Northern Nevada and 90 customers in Southern Owyhee County, to Raft River Rural Electric Cooperative Inc. The closing date of the transaction was April 2, 2001. The area sold to Raft River Rural Electric Cooperative Inc. is located entirely within Idaho Power's load-control area.

Idaho Power Company recently notified the City of Colton that IPC intends to terminate the contract at the end of May in 2005. Contract termination requires three-year advance notification and can be initiated by either party. Peak and energy forecasts used in the IRP assumed termination of the Colton contract at the end of June 2004.

As shown in Table 2, most of the term off-system sales contracts are scheduled to end by the end of 2003. Idaho Power will continue to evaluate the value of term off-system sales, but with the exceptions of the City of Weiser and Raft River Rural Electric Cooperative Inc., Idaho Power has not included the renewal of any term off-system sales contracts in its load projections.

Energy Efficiency and Demand-Side Management

In response to IPUC Order No. 28722, Idaho Power filed a comprehensive Demand-Side Management (DSM) program on July 31, 2001. The filing proposed a ½ percent charge applied to all customer classes to fund new DSM programs. The proposed charge was to be included as a rider on customer bills. A list of program options that could be implemented with DSM funding was included as part of the filing. Idaho Power Company also proposed developing an Energy Efficiency Advisory Group to assist with selecting and evaluating DSM programs if the rider charge for conservation funding is approved. On November 21, 2001, in Order No. 28894, the Idaho Commission postponed consideration of DSM funding until the 2002 PCA filing in April 2002.

The energy conservation improvements attributable to past participation in Idaho Power's DSM programs are reflected in the actual measured loads of recent years and throughout the forecast of projected loads for future years in the planning period.

Idaho Power Company's most current reports to the IPUC and the OPUC regarding DSM programs are attached hereto as *Appendix C, 2002 Conservation Plan*.

Northwest Energy Efficiency Alliance

The Northwest Energy Efficiency Alliance mission is to promote market transformation to energy efficient products and services in the Pacific Northwest. Idaho Power is one of six investor-owned utilities and eight public utilities that provide funding in the region. Idaho Power's continuing commitment to the Alliance is dependent upon regulatory approval of cost recovery.

The Northwest Energy Efficiency Alliance conducts activities such as market research, technology assessment, planning, and brokering collaborations. In addition, the Alliance administers demonstration programs, targets market interventions, develops infrastructures to assist market transformations, and disseminates information. To ensure the effectiveness of its efforts, the Alliance conducts a comprehensive evaluation of each of the projects.

Idaho Power has entered into a Memorandum of Agreement to fund the Northwest Energy Efficiency Alliance through 2004. For that period, Idaho Power's system-wide contribution is estimated to be $1.3 million annually out of an annual Alliance budget of $20 million. The $1.3 million requested contribution is less than the $1.7 million annually that Idaho Power was previously contributing to the Alliance. Idaho Power Company is hopeful that the public utility commissions of Idaho and Oregon will support the funding request.

Idaho Power supports and complements the Alliance activities in its retail service territory in the states of Oregon and Idaho. Due to the small size of the Oregon retail service territory compared to the Idaho retail service territory, most of the costs for participation in the Alliance have been allocated to the Idaho retail service territory. For the same reason, the Idaho Public Utilities Commission has been the primary agency that the Company has looked to for authorization to participate in the Northwest Energy Efficiency Alliance. Idaho Power Company has recently obtained approval from the IPUC for continued participation in the Alliance through the year 2004. The OPUC has consistently expressed its support of the Company's participation in the Alliance by providing funding from Idaho Power's Oregon customers.

Northwest Power Planning Council Regional Efficiency

The Northwest Power Planning Council (NWPPC) has a conservation goal of 300 aMW within three years. The NWPPC suggests that IPC can contribute 80,160 MWh, or just over 9 aMW, to the effort. Idaho Power Company intends to meet the NWPPC goal through a combination of customer and company conservation. Idaho Power Company has a variety of large facilities, including offices, maintenance shops, generation facilities, and distribution and transmission facilities. Conservation at the various IPC facilities is expected to make a significant contribution to the Northwest Power Planning Council conservation goal.

BPA Conservation and Renewable Discount Program

Under the Bonneville Power Administration (BPA) residential exchange program, Idaho Power is eligible to participate in the Conservation and Renewable Discount Program (C&RD). The C&RD is a credit that is made available to Idaho Power in order to further conservation and renewable development in the region. Idaho Power can spend up to $525,000 per year on qualified expenditures through 2004. Qualified expenditures are specified by BPA.

Idaho Power allocates the C&RD credit to residential conservation programs. During the winter of 2001-2002, 14,000 energy efficiency packets were distributed to lower income or high electrical usage customers. Each packet included energy efficiency information and an Energy Star compact fluorescent bulb as an example of energy conservation. Future programs using C&RD funding are in planning stages.

Public-Purpose Programs

Low-Income Weatherization Assistance

Low-Income Weatherization Assistance (LIWA) is a public-purpose program to make weatherization services more affordable for low-income customers. Payments are made to local non-profit agencies participating in state-run weatherization programs in Idaho and Oregon to supplement federal funding. In Idaho, the program is fuel-blind and allows payments for some health and safety measures, as well as weatherization. In Oregon, all dwellings must be electrically heated and all measures must provide cost-effective electricity savings to be eligible for funding. Idaho Power typically contributes 50 percent of the cost for qualifying measures, plus a $75 administration fee, per dwelling. The program also funds weatherization of buildings occupied by tax-exempt organizations.

Oregon Commercial Audit Program

The Oregon Commercial Audit Program is a statutory program specifying that all commercial building customers be notified every year that information regarding energy-saving operations and maintenance measures is available and that commercial energy-audit services can be provided. The audit services are normally provided at no charge to the customer. Customers using more than 4,000 kWh per month may receive a more detailed audit but may be required to pay a portion of the cost.

Oregon Residential Weatherization

The Oregon Residential Weatherization Program is a statutory requirement program specifying annual notification to all residential customers informing them how to obtain energy audits and financing for energy conservation measures. To qualify for an Idaho Power audit or financing, customers must have electric space heat.

Energy Efficiency Promotion Activities

Idaho Power continues to promote the wise, efficient, and safe use of electricity by providing information and education at workshops and conferences. Idaho Power offers informational material, consulting services, energy audits, power quality assistance, audits, and financing to help customers avoid energy problems.

3. Existing and Planned Resources

Hydroelectric Generating Resources

Idaho Power operates 17 hydroelectric generating plants located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,707 MW and median water annual generation equal to approximately 1,071 aMW.

The backbone of the Company's hydroelectric system is the Hells Canyon Complex in the Hells Canyon reach of the middle Snake River. The Hells Canyon Complex consists of the Brownlee, Oxbow and Hells Canyon dams and associated generating facilities. The three plants provide approximately 70 percent of IPC's annual hydroelectric generation and nearly 40 percent of the total energy generation. Water storage in the Brownlee reservoir also enables the Hells Canyon Complex to provide the major portion of IPC's peaking and load-following capability.

Idaho Power's hydroelectric facilities upstream from Hells Canyon include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls and Cascade generating plants. Water storage reservoirs at Lower Salmon, Bliss and C.J. Strike provide for peaking capabilities at these plants. All of the other upstream plants utilize run-of-river stream flow for generation.

Federal Energy Regulatory Commission Relicensing Process

Idaho Power Company's hydroelectric facilities, with the exception of the Clear Lake and Thousand Springs plants, operate under federal licenses regulated by the FERC. The process of relicensing Idaho Power's hydroelectric projects at the end of their initial 50-year license periods is well under way. A license renewal was granted by FERC in 1991 for the Twin Falls project. Applications to relicense the Company's three mid-Snake facilities (Upper Salmon, Lower Salmon and Bliss) were submitted to FERC in December 1995. The application to relicense the Shoshone Falls project was filed in May 1997. The application to relicense the C.J. Strike project was filed in November 1998. Relicensing applications for the remaining hydroelectric facilities, including Swan Falls, the Upper and Lower Malad plants, and the Hells Canyon Complex, will be prepared and submitted during the current ten-year planning period. The relicensing schedule for hydroelectric projects is shown in Table 3.

Failure to relicense existing hydropower projects at a reasonable cost would create upward pressure on the current low rates available to Idaho Power customers. The relicensing process may potentially decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation and enhancement (PM&E) imposed as a condition for relicensing. Idaho Power Company's goal in relicensing is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment. No reduction of the available capacity of hydroelectric plants to be relicensed was assumed as part of the 2002 Integrated Resource Plan. If capacity reductions occur as a result of the process,

Table 3 Idaho Power Company
Hydropower Project Relicensing Schedule

Project	FERC License Number	Nameplate Capacity (MW)	Current License Expires	File FERC License Application
Bliss	1975	75	Dec 1997	Dec 1995
Lower Salmon	2061	60	Dec 1997	Dec 1995
Upper Salmon	2777	34.5	Dec 1997	Dec 1995
Shoshone Falls	2778	12.5	May 1999	May 1997
C.J. Strike	2055	82.8	Nov 2000	Nov 1998
Upper/Lower Malad	2726	21.8	July 2004	July 2002
Hells Canyon Complex	1971	1166.9	July 2005	July 2003
Swan Falls	503	25	June 2010	June 2008

then Idaho Power Company would be forced to add other capacity resources in order to maintain reliability.

Collaborative Process

Idaho Power is seeking to address concerns regarding hydro generation by working with various public and private agencies and organizations and pursuing a collaborative approach to the relicensing of the hydro generation facilities. Discussions with state and federal agencies have been initiated to investigate ways in which the low costs and flexibility of existing hydro generation can be retained for the benefit of Idaho Power customers.

Idaho Power has established a collaborative team consisting of federal and state resource agencies, tribes, regional and local governments, non-governmental organizations, industrial and commercial customers, regulatory bodies and other interested entities to actively participate with Idaho Power by exchanging information and providing input on components of new license applications, including Idaho Power's PM&E proposals. The goals of the collaborative process are to:

– Involve resource agencies and the public throughout the relicensing process for Idaho Power's hydroelectric projects.

– Foster open exchange of views among participants.

– Facilitate well-defined and focused study plans.

– Encourage agreements among participants on the content of applications for relicensing, on PM&E plans and on conditions of new licenses.

– Ensure efficient use of resources and avoid unnecessary study and process costs.

– Provide participants with more control and certainty in the relicensing process through better relationships with affected entities and the public.

– Reduce the likelihood and extent of potential litigation.

The FERC has expressed encouragement for the collaborative process, and FERC representatives routinely attend the collaborative team meetings.

Environmental Analysis

The National Environmental Policy Act requires that FERC perform an environmental assessment (EA) of each hydropower license application to determine whether federal action will significantly impact the quality of the natural environment. If so, then an environmental impact statement (EIS) must be prepared prior to granting a new license. As part of the EA for Idaho Power's mid-Snake and Shoshone Falls applications, FERC visited Idaho during July 1997 to receive public and agency input through scoping meetings. FERC issued additional information requests (AIRs) in 1998 for the mid-Snake project. FERC also visited Idaho to receive public and agency input at a scoping meeting held in September 1999. FERC issued AIRs for the C.J. Strike project in 1999. A draft EIS was issued on the mid-Snake projects in January 2002, and the FERC was in Idaho in February 2002 to receive public and agency comment. Completion of the final EIS regarding the mid-Snake projects is expected later in 2002.

FERC is currently developing an approach to a cumulative environmental analysis of the Snake River from Shoshone Falls through the Hells Canyon Complex. Once the analysis is complete, FERC will consider recommendations from affected state and federal agencies and issue license orders for the affected projects, including required PM&E measures. The process may take from two to five years in the case of the Shoshone Falls, Upper Salmon, Lower Salmon and Bliss projects. Opportunity for additional public comment will occur before the license orders are issued. If a project's current license expires before a new license has been issued, annual operating licenses are issued by FERC pending completion of the licensing process.

Salmon Recovery Program

In recent years, the movement of water through the hydroelectric system to assist spawning and migration of salmon has substantially impacted the amount and timing of hydroelectric generation. For that reason, IPC actively monitors and participates in regional efforts to develop a program of actions to assist the recovery of the endangered salmon populations.

Hydroelectric Relicensing Uncertainties

Idaho Power Company is optimistic that the hydro project relicensing will be completed in a timely fashion. However, prior experience indicates that the relicensing process will probably result in an increase in the costs of generation from the relicensed projects. The increased costs are usually associated with the requirements imposed on the projects as a condition of relicensing. As previously described in the discussion of the ongoing FERC collaborative process, Idaho Power is currently discussing relicensing issues with the collaborative team. Initial discussions with members of the collaborative team have begun concerning proposed changes in project operations that would impact the availability of electric energy from the relicensed projects. Once complete, Idaho Power will be able to better estimate the potential impacts of the proposed requirements on energy-generating capability. The FERC relicensing process then provides IPC with time to assess proposed requirements and to develop and present responses to the proposals. As a result, Idaho Power cannot reasonably estimate at this time the impact of the relicensing process on the generating capability of the relicensed projects. At the time of the 2004 IRP, Idaho Power will have better information regarding the power generation impacts of relicensing.

Thermal Generating Resources

Bridger

Idaho Power Company owns a one-third share of the Jim Bridger (Bridger) coal-fired plant located near Rock Springs, Wyoming. The plant consists of four nearly identical generating units. Idaho Power's one-third share of the generating capacity of Bridger currently stands at 707 MW after the upgrade of the high-pressure/intermediate-pressure (HP/IP) turbines on all four generating units. The fourth unit HP/IP upgrade was completed in June of 2000. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power's share of the Bridger plant is approximately 627 aMW.

Valmy

Idaho Power Company owns a 50 percent share, or approximately 261 MW of capacity of the 521 MW Valmy plant located east of Winnemucca, Nevada. The plant, which consists of one 254 MW unit and one 267 MW unit, is owned jointly with Sierra Pacific Power Company. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power's share of the Valmy plant is approximately 231 aMW.

Boardman

Idaho Power owns a 10 percent share of the 552 MW coal-fired plant near Boardman, Oregon, operated by Portland General Electric Company. After adjustment for scheduled maintenance periods and estimated forced outages and de-ratings, the annual energy-generating capability of Idaho Power's share of the Boardman plant is approximately 47 aMW.

Evander Andrews Power Complex

In addition to the three coal-fired steam-generating plants, Idaho Power owns and operates the Evander Andrews Power Complex, a 90 MW natural gas-fired combustion turbine plant and the associated switchyard. The 12-acre complex, constructed during the summer of 2001, is located northwest of Mountain Home, Idaho. The complex was named in honor of Air Force Master Sergeant Evander Andrews, a member of a civil engineering squadron from Mountain Home Air Force Base. Master Sergeant Andrews was the first U.S. casualty of Operation Enduring Freedom.

The Andrews Complex will operate as needed to support system load or in response to favorable market conditions.

Salmon Diesel

Idaho Power owns and operates two diesel generation units located at Salmon, Idaho. The Salmon diesels produce 5.5 MW and are primarily operated during emergency conditions.

Purchased & Exchanged Generating Resources

Garnet Purchased-Power Contract

Idaho Power Company has entered into an agreement to purchase up to 250 MW of capacity and associated energy during periods of peak need from the Garnet Energy LLC facility. As proposed, the facility would be a nominal 250 MW natural gas-fired combined-cycle combustion turbine electrical generation facility capable of expansion to a nominal 500 MW project.

The planned site for the Garnet facility is be located in Canyon County about 1 mile south of Middleton, Idaho, on 30 acres east of Middleton Road, south of the south channel of the Boise River. The location is approximately 1.25 miles north of the future Locust Grove-Caldwell transmission line and about 3 miles west of the Williams Northwest natural gas pipeline.

Public Utility Regulatory Policies Act

Idaho Power purchases energy from independent power producers operating as qualifying facilities (QF) under the Public Utility Regulatory Policies Act of 1978, at avoided cost rates established by the public utility commissions of Idaho and Oregon. The *Technical Appendix* lists the various QF projects. As of December 2001, the various QF projects were delivering 93 aMW of power to IPC and its customers.

Exchanges

In the past, seasonal load diversity between Idaho Power and the rest of the region has enabled IPC to make term power exchanges with other regional utilities, maximizing the utilization of IPC's existing generation and transmission resources.

An exchange agreement with Montana Power Company (Northwestern Energy) provides for the delivery to Montana of 108,000 MWh during the three-month period from December through February. Deliveries are assumed to be constant at 50 aMW. In return, Montana Power Company delivers to Idaho 118,000 MWh during the three-month June through August period. Power receipts are assumed to be 10 aMW in June and 75 aMW in July and August.

Under a similar agreement, 126,000 MWh are delivered to Seattle City Light from November through February and returned to Idaho Power from July through September. Deliveries to Seattle City Light are assumed to be 25 aMW in November and 50 aMW in December, January and February. Power receipts are assumed to be 100 aMW in July, 54 aMW in August and 16 aMW in September. The last transfer of energy in the Seattle agreement occurs in September 2002 and the last transfer of energy in the Montana agreement occurs in December 2003.

Idaho Power plans to continue investigating opportunities for cost-effective power exchanges as a method to manage projected surpluses and deficiencies – especially with the Montana Exchange ending in December 2003. Idaho Power has contacted Northwestern Energy to discuss continuing an energy exchange between the companies.

Additionally, properly timed seasonal exchanges or wholesale purchases delivered to the east side of the IPC system will result in a direct reduction in the number of hours of transmission deficit from the Pacific Northwest. East side deliveries can directly reduce the load and congestion on the Brownlee East transmission path. For these reasons, IPC continues to pursue cost effective exchanges delivered to the east side of the Idaho Power system.

Transmission Resources

Description

The Idaho Power transmission system is a key element serving the needs of its retail customers. The 230 kilovolt (kV) and higher voltage main grid system is essential for the delivery of bulk power supply. Figure 1 shows the principal grid elements of Idaho Power's high-voltage transmission system.

Capacity and Constraints

Idaho Power Company's transmission connections with regional utilities provide paths over which off-system purchases and sales are made. The transmission interconnections and the associated power transfer capacities are identified in Table 4. The capacity of a transmission path may be less than the sum of the individual circuit capacities. The difference is due to a number of factors, including load distribution, potential outage impacts, and surrounding system limitations. In addition to the restrictions on interconnection capacities, there are other internal transmission constraints that may limit IPC's ability to access specific energy markets. The internal transmission paths needed to import resources from other utilities and their respective potential constraints are shown in Figure 1 and Table 4.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Northwest Interconnection shown in Table 4. Brownlee East is comprised of the 230 kV and 138 kV lines east of the Brownlee/Oxbow/Quartz area and the Summer Lake-Midpoint 500 kV line. The constraint on the Brownlee East transmission path is within Idaho Power's main transmission grid and located in the area between Brownlee and Boise on the west side of the system.

The Brownlee East path is most likely to face summer constraints. The summer constraints result from a combination of Hells Canyon Complex hydro generation flowing east into the Treasure Valley, concurrent with term transmission wheeling obligations and purchases from the Pacific Northwest. The term transmission also flows southeast into and through Southern Idaho. Significant congestion affecting southeast energy transmission flow from the Pacific Northwest also occurs during the months of November and December.

The Brownlee East constraint is the primary restriction on imports of energy from the Pacific Northwest. If new resources are sited west of this constraint, additional transmission capacity will be required to remove the existing Brownlee East transmission constraint and deliver the energy from the additional resources to the Boise/Treasure Valley load area.

A new 10-mile, 230 kV line between Brownlee and Oxbow is planned to relieve the operating limitations at Oxbow and Hells Canyon. The transmission upgrade will increase the Brownlee East capacity by approximately 100 MW, thereby increasing IPC's ability to import additional energy from the Pacific Northwest for native load use. The transmission upgrade is expected to be completed and in service by the fall of 2004.

Brownlee North Path

The Brownlee North path is a part of the Northwest Interconnection and consists of the Hells Canyon-Brownlee and Oxbow-Brownlee 230 kV double circuit line. The Brownlee North path is most likely to face constraints during the summer months when high southeast energy flows and high hydro production levels coincide. Congestion on the Brownlee North path also occurs during the winter months of November and December due to large southeast energy transfers.

Northwest Path

The Northwest path consists of the 500 kV Summer Lake-Midpoint line, the three 230 kV lines between the Northwest and Brownlee, and the 115 kV interconnection at Harney. Deliveries of purchased power from the Pacific Northwest often flow over these lines. During low water conditions, total purchased power needs may exceed the capability of the path. If new resources are sited west of this constraint, additional transmission capability will be needed to transmit the energy into the IPC control area.

Borah West Path

The Borah West transmission path is within Idaho Power's main grid transmission system located west of the Eastern Idaho, Utah Path C, Montana and Pacific (Wyoming) interconnections shown in Table 4. The Borah West path consists of the 345 kV and 138 kV lines west of the Borah/Brady/Kinport area. The Borah West path will be of increasing concern because the capacity of this path is fully utilized by existing term obligations. If new resources are constructed or acquired from sites east of the Borah West constraint, additional transmission facilities will need to be constructed to transmit the energy to customers in the Treasure Valley and Magic Valley.

Figure 1 Idaho Power Company Transmission System

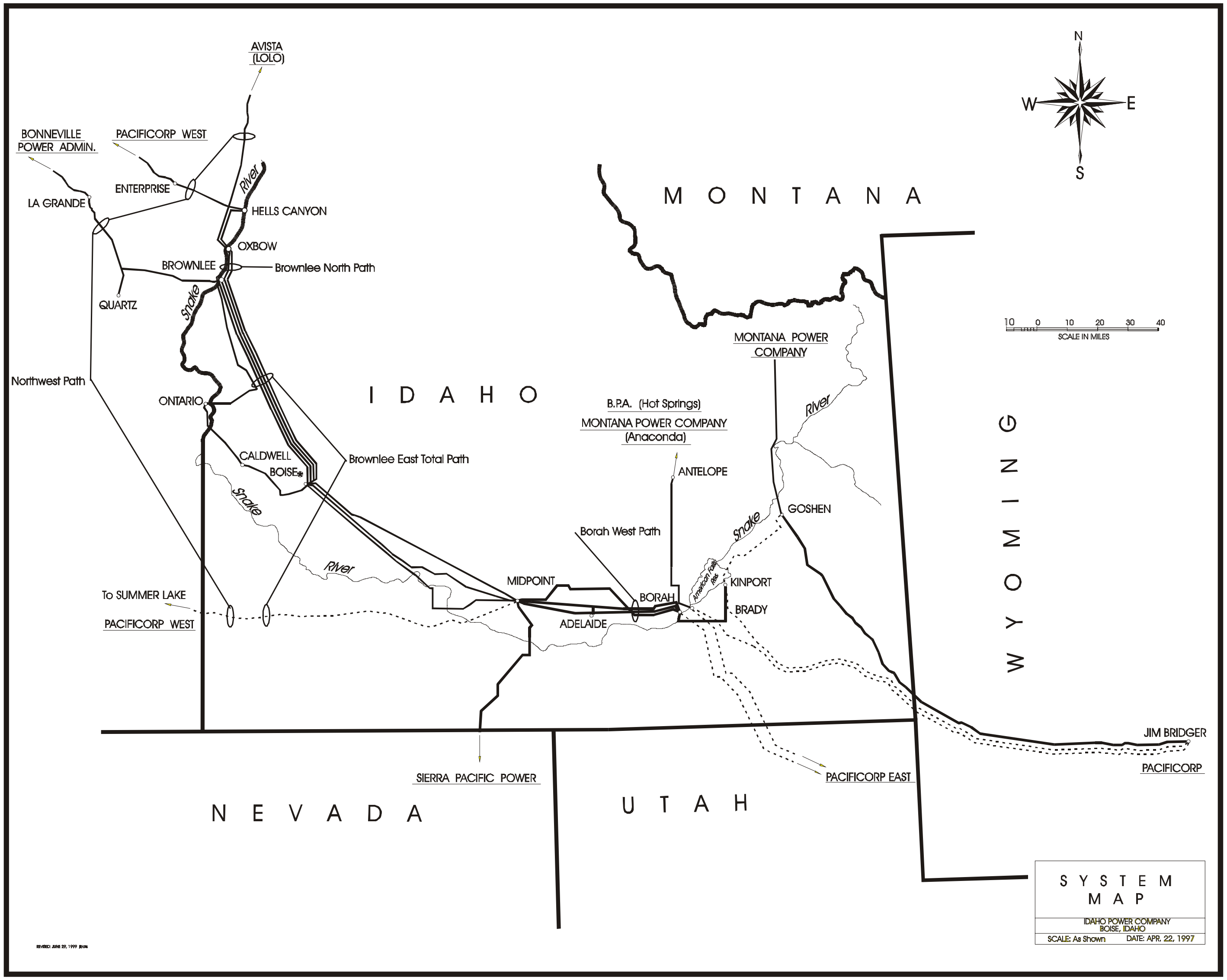


Table 4 Idaho Power Company Transmission Interconnections

Transmission Interconnections	To Idaho	From Idaho	Line or Transformer	Connects Idaho Power To
Northwest	1,100 to	2,400 MW	Oxbow - Lolo 230 kV	Washington Water Power
	1,200 MW		Midpoint - Summer Lake 500 kV	PacifiCorp (PPL Division)
			Hells Canyon - Enterprise 230 kV	PacifiCorp (PPL Division)
			Quartz Tap - LaGrande 230 kV	Bonneville Power Administration
			Hines - Harney 138/115 kV	Bonneville Power Administration
Sierra	262 MW	500 MW	Midpoint - Humboldt 345 kV	Sierra Pacific Power
Eastern Idaho[1]			Kinport - Goshen 345 kV	PacifiCorp (UPL Division)
			Bridger - Goshen 345 kV	PacifiCorp (UPL Division)
			Brady - Antelope 230 kV	PacifiCorp (UPL Division)
			Blackfoot - Goshen 161 kV	PacifiCorp (UPL Division)
Utah (Path C)[2]	775 to	830 to	Borah - Ben Lomond 345 kV	PacifiCorp (UPL Division)
	950 MW	870 MW	Brady - Treasureton 230 kV	PacifiCorp (UPL Division)
			American Falls - Malad 138 kV	PacifiCorp (UPL Division)
Montana[3]	79 MW	79 MW	Antelope - Anaconda 230 kV	Montana Power Company
	87 MW	87 MW	Jefferson - Dillon 161 kV	Montana Power Company
Pacific (Wyoming)	600 MW	600 MW	Jim Bridger 345/230kV	PacifiCorp (Wyoming Division)

Power Transfer Capacity for Idaho Power Company Interconnections

1 The Idaho Power-PacifiCorp interconnection total capacities in Eastern Idaho and Utah include Jim Bridger resource integration.
2 The Path C transmission path also includes the internal PacifiCorp Goshen-Grace 161 kV line.
3 The direct Idaho Power-Montana Power schedule is through the Brady-Antelope 230kV line and through the Blackfoot-Goshen 161 kV line that are listed as an interconnection with PacifiCorp. As a result, Idaho-Montana and Idaho-Utah capacities are not independent.

Transmission Uncertainties

FERC Order 2000

On December 15, 1999, the FERC issued Order 2000 to encourage voluntary membership in regional transmission organizations (RTO). The order required all public utilities that own, operate or control interstate transmission facilities to file by October 15, 2000 a proposal for an RTO. Idaho Power Company has been an active participant in efforts to determine an appropriate structure for RTO West, a RTO for the Pacific Northwest. While the proposed restructuring changes will not alter the physical capability of the transmission system, it is uncertain how an RTO structure will affect Idaho Power's use of its transmission system.

FERC Order 888

On May 10, 1996, FERC issued Order 888. The FERC intent of Order 888 was to promote the use of transmission facilities for competitive markets at the wholesale level. Because of the geographic location of Idaho Power's transmission facilities, Idaho Power anticipates that multiple entities may request transmission capacity in Idaho Power's main grid transmission system to transport power from the Pacific Northwest to the Desert Southwest. Under the auspices of FERC Order 888, utilities can be compelled to construct additional transmission facilities to increase capacity if the party seeking to use the increased capacity pays the cost of adding the capacity. In fact, use of Idaho Power's transmission facilities has already been the subject of litigation before the FERC brought by Arizona Public Service (APS) against Idaho Power relating to APS's desire to use Idaho Power's transmission system for term transactions. In light of the FERC support for open access facilitating transactions at the wholesale level, planning for future transmission resources must anticipate additional regulatory requirements being placed on the transmission system as a result of FERC Orders 888 and 2000.

FERC Docket No. RM01-12-000

On April 10, 2002, in Docket No. RM01-12-000, entitled Electricity Market Design and Structure, the FERC issued a Notice of Options paper to initiate discussions on proposed rule making to address standardized transmission service and wholesale market design. While the rule making is in the very early stages, an initial review indicates that it could have considerable impact on Idaho Power's transmission operations and recovery of costs for transmission service. Idaho Power Company is working with the other RTO West participants to respond to the rule making.

Western Electricity Coordinating Council Operating Transfer Capability Process

Since the transmission disturbances of the summer of 1996, transmission system capabilities have come under increasing scrutiny. The Western Electricity Coordinating Council (WECC) has adjusted the transfer capability on many transmission lines. A transmission operator no longer has the assurance that all of the line capability will be fully usable in the future. New interactions with other existing transmission paths, previously unidentified, can force reductions in existing transmission capability.

4. Adequacy of Existing and Planned Resources

Idaho Power Company is committed to generate and deliver reliable, low-cost power for its customers. Reliability and quality of service are directly impacted by the adequacy of IPC's electric supply.

Idaho Power has specified a resource adequacy criterion requiring new resources be acquired at the time that the resources are needed to meet forecast energy growth, assuming a water condition at the 70th percentile for hydroelectric generation. Idaho Power is proposing to change from the previous median water-planning criterion. The change is discussed in greater detail later in this chapter.

The 70th percentile means that Idaho Power plans generation based on stream flows that occur in seven out of 10 years on average. Stream-flow conditions are expected to be worse than the planning criteria 30 percent of the time. Idaho Power plans to meet WECC criteria for reserves. The WECC criteria currently requires Idaho Power to maintain 330 MW of reserves above the forecast peak load to cover an unexpected loss equal to Idaho Power's share of two Bridger generation units.

A 70th percentile monthly water planning differentiates Idaho Power from other Northwest utilities, which typically plan resources based upon having annual generating capability sufficient to meet forecast annual energy requirements under critical water conditions. Critical water conditions are generally defined to be the worst, or nearly worst, annual water conditions based on historical stream flow records.

Using the 70th percentile water-planning criterion produces capacity and energy surpluses whenever stream flows are greater than the 70th percentile. Temporary off-system sales of surplus energy and capacity provide additional revenue and reduce the costs to IPC customers. During months when Idaho Power faces an energy or capacity deficit because of low stream flow, excessive demand, or for any other reason, Idaho Power plans to purchase off-system energy and capacity on a short-term basis to meet system requirements.

Low-water (90th percentile) scenarios have been evaluated and included in the 2002 Integrated Resource Plan to demonstrate the viability of IPC's plan to serve peak and energy loads under low-water conditions. The evaluations include consideration of IPC's transmission capability at times of lower stream flows.

Impact of Salmon Recovery Program on Resource Adequacy

The December 1994 Amendments to the Northwest Power Planning Council's fish and wildlife program and the biological opinions issued under the Endangered Species Act (ESA) for the four lower Snake River federal hydroelectric projects call for 427,000 acre-feet of water to be acquired by the federal government from willing lessors upstream of Brownlee Reservoir. The acquired water is then to be released during the spring and summer months to assist ESA-listed juvenile salmonids (spring, summer, fall Chinook and steelhead) migrating past the four federal hydroelectric projects on the lower Snake River. In the past, water releases from Idaho Power's hydroelectric generating plants have been modified to cooperate with the federal efforts. Idaho Power also adjusts flows in the late fall of each year to assist with the spawning of fall Chinook below the Hells Canyon Complex.

Because of the practical, physical, and legal constraints that federal interests must deal with in moving 427,000 acre-feet of water out of Idaho, Idaho Power has pre-released, or shaped, a portion of the acquired water with water from Brownlee Reservoir and later refilled the reservoir with water leased under the federal program. At times, Idaho Power has also contributed water from Brownlee to assist with the federal efforts to improve salmonid migration past the lower Snake federal projects.

Idaho Power's cooperation with the federal programs has been pursuant to an agreement with the BPA that provided for an energy exchange which reimbursed Idaho Power for any energy or generating capacity lost by the shaping or modification of flows. The BPA agreement insured that Idaho Power customers were not adversely affected by Idaho Power's cooperation with federal efforts.

The agreement with the BPA expired on April 15, 2001, and has not been renewed. As such, the energy exchange with the BPA that was modeled in the 2000 IRP is not included in the 2002 IRP. Idaho Power does not intend to modify or otherwise shape flows from its hydroelectric projects to address federal responsibilities in the lower Snake River in the absence of an appropriate agreement with the BPA or other federal interests. While such an agreement may be negotiated in the future, Idaho Power Company does not intend to enter into any such agreement that would adversely affect Idaho Power customers or require the construction of additional resources.

Water Planning Criteria for Resource Adequacy

Idaho Power Company has an obligation to serve customer loads regardless of the water conditions that may occur. In the past, when water conditions were at low stream-flow levels, IPC relied on market purchases to serve customer loads. Historically, IPC's plan has been to acquire or construct resources that will eliminate expected energy deficiencies in every month of the forecast period whenever median or better water conditions exist, recognizing that when water levels are below median, IPC historically relied on market purchases to meet any deficits.

In connection with the recent market price movements to historical highs during the summer of 2001, IPC has reevaluated the planning criteria. The public, the Idaho Public Utilities Commission, and the Idaho legislature all have suggested that Idaho Power may place too great a reliance on market purchases based upon the IRP planning criteria. Greater planning reserve margins or the use of more conservative water planning criteria have been suggested as methods requiring IPC to acquire more firm resources and reduce the likelihood of market purchases.

Due to the public input to the planning process, IPC is proposing a resource plan based upon a lower-than-median level of water. In the current resource plan, IPC is using the 70^{th} percentile water conditions and load conditions for resource planning. However, IPC will continue to evaluate resource adequacy under a median water condition and include that evaluation as part of the Integrated Resource Plan.

Idaho Power will continue to analyze its ability to serve customers' peak and energy needs under a low-water condition (90^{th} percentile) as well. Based on the low-water analyses, IPC believes that it will be difficult to acquire and deliver short-term resources from the Pacific Northwest in amounts sufficient to satisfy peak-hour deficiencies during low-water conditions.

Historically, Idaho Power has been able to reasonably plan for the use of short-term power purchases to meet temporary water-related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power customers typically have summer peaking requirements while the other utilities in the Pacific Northwest region have winter peaking requirements.

Although Idaho Power has transmission interconnections to the Southwest, the Northwest market is the preferred source of purchased power. The Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho Power's system tend to be smaller, less liquid, and have greater transmission distances.

Under the low water and high-load conditions, projected peak-hour loads are likely to cause peak-hour transmission overloads from the Pacific Northwest. The transmission overloads may present significant difficulties as early as the summers of 2003 and 2004 (transmission adequacy is discussed later in this chapter). Recent experiences indicate that, even when Northwest power is available, the short-term prices can be quite high and volatile.

Recent market price events demonstrate that while IPC has been able to rely on market purchases, the price can be high. The price risk has led to the development of the Risk Management Policy discussed in the Introduction. The Risk Management Policy represents collaboration of Idaho Power, the IPUC staff, and interested customers in Commission Case IPC-E-01-16.

The primary uncertainties associated with planned short-term power purchases are the availability of adequate Northwest to Idaho transmission capacity to allow imports at the times when needed, and uncertainty concerning the market prices of the purchases.

Planning Scenarios

Median Water, Median Load (Energy)

Figure 2 shows the monthly energy surpluses and deficiencies associated with median water and the most probable or expected future load scenario. With median water, median loads, and the additional generation from both the Evander Andrews Power Complex near Mountain Home and Garnet in 2005, IPC will experience energy deficiencies in the winter months starting in December 2006. Winter deficiencies are expected to increase from approximately 38 aMW in 2006 to approximately 190 aMW in 2011. Additionally, IPC will experience summer energy deficiencies starting in July 2008. Summer deficiencies are expected to increase from approximately 28 aMW in 2008 to approximately 178 aMW by 2011.

Median Water, Median Load (Peak)

At the time of the peak monthly system load, additional energy is required to satisfy the peak demand. Figure 3 shows that, for the median water and median load scenario, additional resources must be purchased in the summer beginning in June 2002 and in the winter starting in December 2004. Under the median water and median load scenario, deficiencies are generally limited to June, July, November, and December; however, peak-hour energy deficiencies do begin to occur in other months starting in 2010.

70^{th} Percentile Water, 70^{th} Percentile Load (Energy)

When below-normal water and higher-than-expected load conditions occur, a greater number of months are expected to have deficiencies than in the median water and median load scenario. Figure 4 shows that winter deficiencies begin in December 2002 with initial deficiencies of approximately 10 aMW increasing to approximately 277 aMW by November 2011. Summer deficiencies in June and July are expected to increase from approximately 45 aMW in 2004 to approximately 293 aMW in 2011. Initial surpluses in August, September and October are expected to become deficiencies starting in August 2006, at 5 aMW and increasing to 200 aMW by September 2011.

70^{th} Percentile Water, 70^{th} Percentile Load (Peak)

Figure 5 illustrates that with 70^{th} percentile water and 70^{th} percentile load conditions, summer peak-hour energy deficiencies occur starting in June 2002 at 161 MW and increase to 610 MW in July 2011. Winter peak-hour deficiencies occur beginning in December 2002 at 107 MW and increase to 314 MW in November 2011. Peak-hour energy deficiencies are limited to June, July, November and December until 2006, when deficiencies begin to occur in other months. By 2011, deficiencies occur in 11 of 12 months.

90^{th} Percentile Water, 70^{th} Percentile Load (Energy)

Figure 6 illustrates that under the 90^{th} percentile water, 70^{th} percentile load scenario, summer deficiencies occur in all years starting in June 2002, with 164 aMW, and increasing to 429 aMW in July 2011. Winter deficiencies also occur in all years starting in December 2002 at 101 aMW and increasing to 316 aMW by December 2011. By 2005, deficiencies occur in 9 of 12 months; by 2010, all months are deficit.

90^{th} Percentile Water, 70^{th} Percentile Load (Peak)

The pattern of deficiencies for the 90^{th} percentile water, 70^{th} percentile load scenario is similar to the pattern of deficiencies for the 70^{th} percentile water, 70^{th} percentile load scenario. Deficiencies in the peak months are typically 40 to 60 MW greater because of changes in water conditions. Monthly surpluses and deficiencies for the 90^{th} percentile water, 70^{th} percentile load growth are shown in Figure 7.

Figure 2 Monthly Energy Surplus / Deficiency
Median Water, Median Load, Existing Resources with Garnet

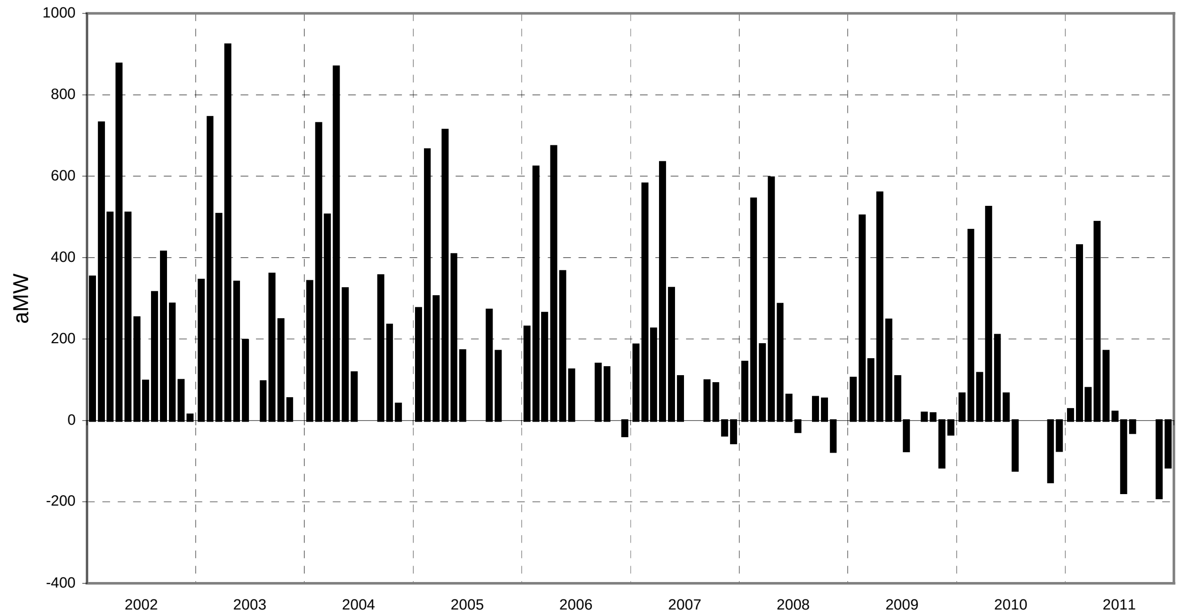


Figure 3 Monthly Peak-hour Surplus / Deficiency
Median Water, Median Load, Existing Resources with Garnet

Figure 4 Monthly Energy Surplus / Deficiency
70th Percentile Water and Load, Existing Resources with Garnet

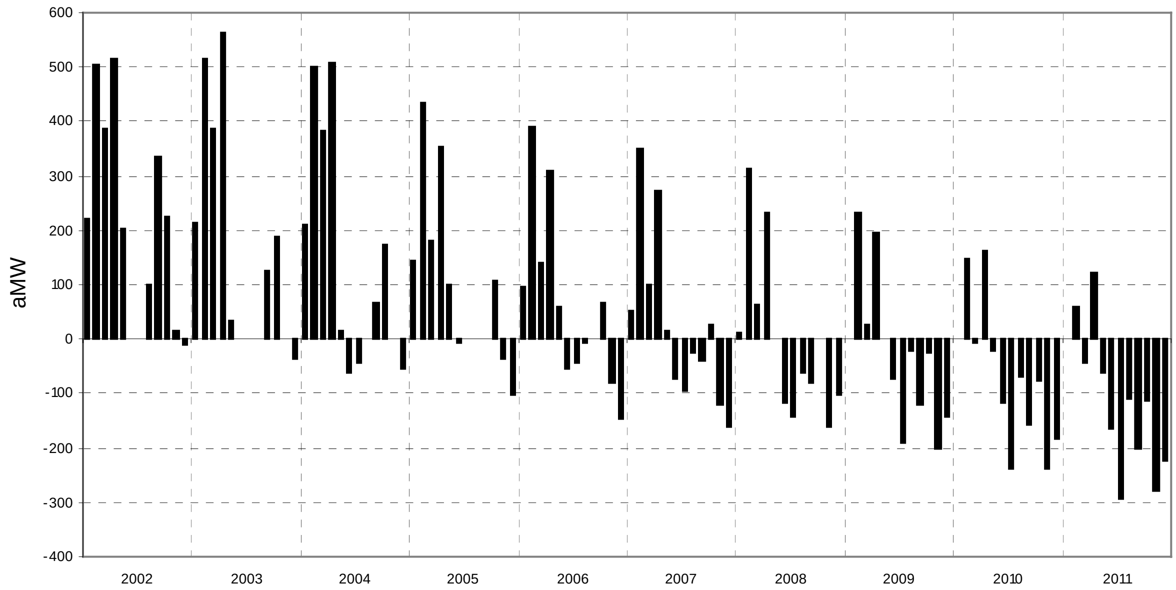


Figure 5 Monthly Peak-hour Surplus / Deficiency
70th Percentile Water and Load, Existing Resources with Garnet

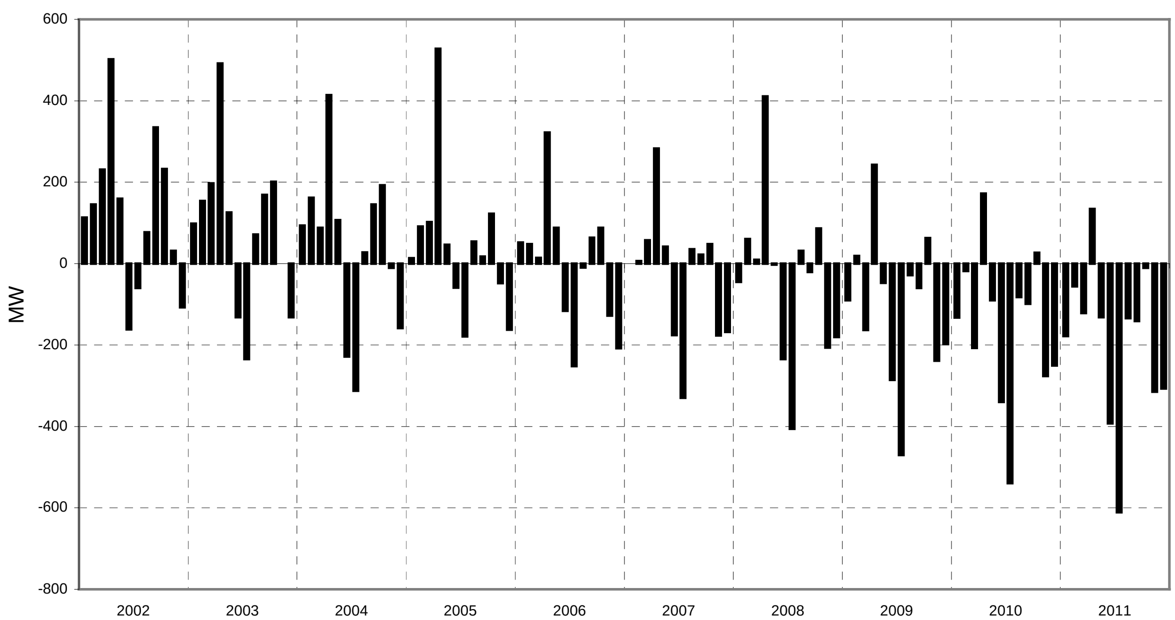


Figure 6 Monthly Energy Surplus / Deficiency
90th Percentile Water, 70th Percentile Load, Existing Resources with Garnet

Figure 7 Monthly Peak-hour Surplus / Deficiency
90th Percentile Water, 70th Percentile Load, Existing Resources with Garnet

Transmission Adequacy

Prior to 2000, Integrated Resource Plans have emphasized construction or acquisition of generating resources to satisfy load obligations. Transmission limitations were not viewed as a major impediment to Idaho Power's purchasing power to meet its service obligations. The 2002 edition of the IRP, as well as the 2000 IRP, recognizes that transmission constraints have begun to place limits on purchased power supply strategies. To better assess the adequacy of the power supply and the transmission system, IPC analyzed peak-hour transmission conditions.

The transmission adequacy analysis reflects IPC's contractual transmission obligations to serve BPA loads in Southern Idaho. The BPA loads are typically served with energy and capacity from the Pacific Northwest. Analyzing the transmission limitations during the peak hour of each month allows IPC to assess the adequacy of the transmission system to serve IPC customers and BPA customers with energy from the Pacific Northwest.

The results of the transmission analyses indicate that the Brownlee East path is most likely to face transmission constraints. The transmission analysis shows monthly peak-hour transmission deficiencies when the IPC resource deficiencies are met by energy purchases from the Pacific Northwest at the same time the transmission system is delivering energy to BPA customers in Southern Idaho.

Figure 8 represents the monthly peak-hour transmission deficiencies for a median water and median load condition. The magnitude of the transmission deficiency is 21 MW in July 2003 and 84 MW in July 2004. Assuming that Garnet is available in June 2005, the next transmission deficiency occurs in July of 2006 and has a magnitude of approximately 45 MW. July peak transmission deficiencies for subsequent years increase by approximately 70-80 MW per year.

Figure 9 represents the monthly peak-hour transmission deficiencies for a 70th percentile water and 70th percentile load condition. The magnitude of the transmission deficiency is 86 MW in July 2003 and 180 MW in July 2004. Assuming that Garnet is available in June 2005, then the July 2005 transmission deficiency is reduced to 25 MW. Transmission deficiencies for subsequent July peaks increase by approximately 75-90 MW per year. By 2010, transmission deficiencies begin to appear in December.

Figure 10 represents the monthly peak-hour transmission deficiencies for a 90th percentile water and 70th percentile load condition. The magnitude of the transmission deficiencies is 141 MW in July 2003 and 225 MW in July 2004. Assuming that Garnet is available in June 2005, the July 2005 deficiency is 92 MW. Transmission deficiencies for subsequent July peak conditions increase by approximately 75-90 MW per year. By the winter season of 2010-2011, transmission deficiencies begin to appear in December and January.

Figure 8 Monthly Peak-hour NW Transmission Deficit
Median Water / Median Load

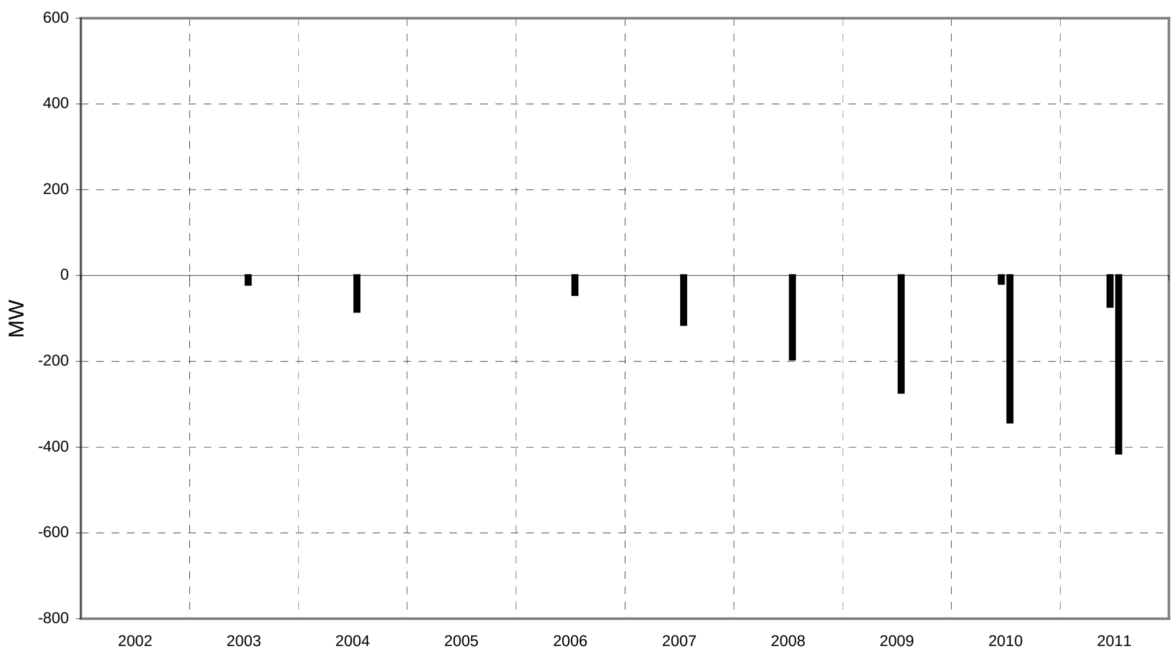


Figure 9 Monthly Peak-hour NW Transmission Deficit
70th Percentile Water, 70th Percentile Load, Existing Resources with Garnet

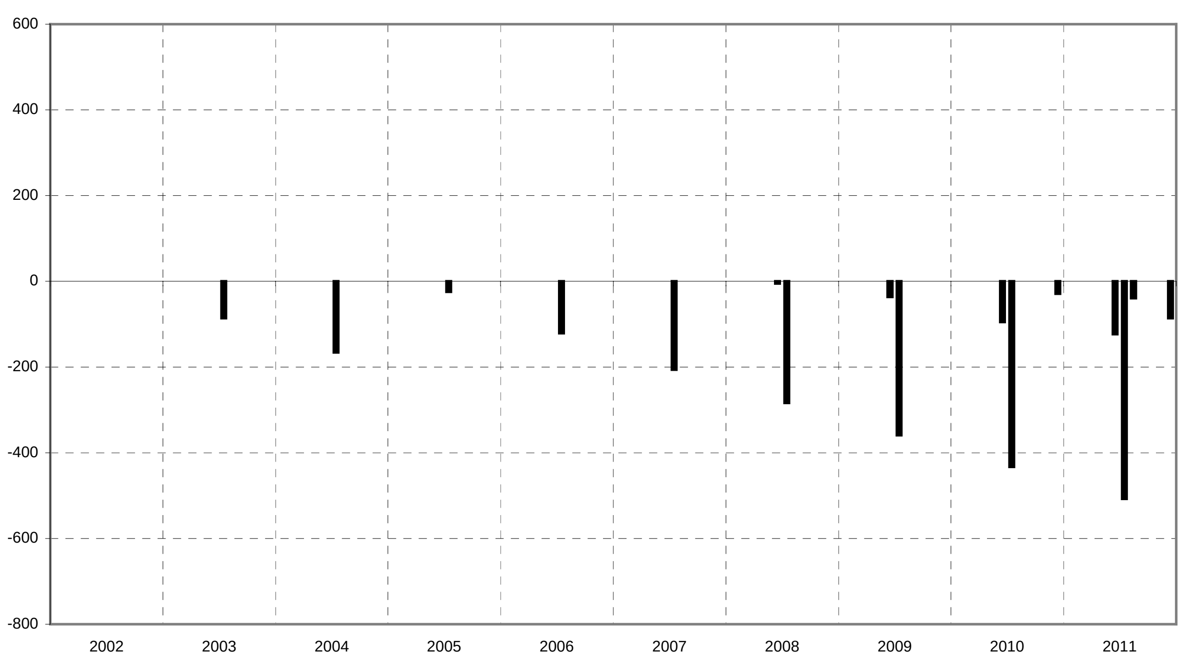
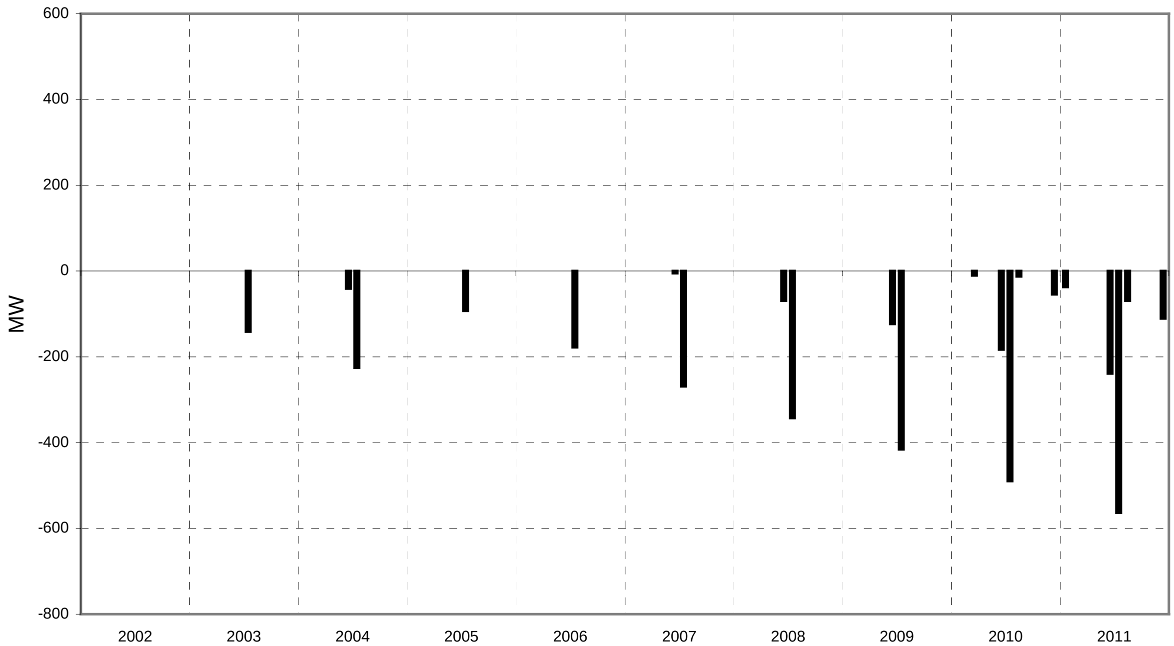


Figure 10 Monthly Peak-hour NW Transmission Deficit
90th Percentile Water, 70th Percentile Load, Existing Resources with Garnet



5. Future Resource Options

Idaho Power's primary resource options for the planning period include purchases of power from the wholesale market, the acquisition of additional generating resources and, to a lesser extent, pricing options and demand-side management programs. The information about each resource option required for resource planning includes capacity and energy capability, expected resource life, seasonal availability, dispatchability, investment and operating costs, and fuel cost.

Identification of the resource options themselves does not constitute a resource plan, but the specification of resource options is a first step in the resource planning process. Included in the first step is a cost analysis of potential generating resources sited at generic locations. The cost analysis assists in the initial economic ranking of all resources under consideration.

After the cost of each resource is determined for generic locations, a more focused analysis of selected resources is performed to establish resource costs based specifically on Idaho or Pacific Northwest regional data. Resource costs associated with Northwest- and Idaho-sited technologies are discussed in greater detail later in this chapter, as well as in Chapter 6.

Purchased and Exchanged Generation

Market Purchases

In the 1997 IRP, Idaho Power chose supplemental seasonal energy and capacity purchases as the near-term strategy to optimize the use of company-owned resources and meet customer loads at the least cost. That strategy had been successful and was continued in the 2000 IRP. Idaho Power had been able to take advantage of abundant supplies of off-system surplus energy and available transmission access to supplement the Company's own low-cost generation resources. In 2001, IPC and many other Northwest utilities experienced low-water conditions and once again relied on the market place to satisfy deficiencies. During that spring and summer, market prices moved to unprecedented levels, often in the hundreds of dollars per MWh. While power was available for purchase, the cost to IPC and its customers was extremely high.

Idaho Power plans to continue using, but much less frequently, seasonal energy and capacity purchases to optimize utilization of Company-owned resources. By emphasizing a 70th percentile water planning criteria, the Company plans to have adequate resources available to satisfy all of its customers' monthly energy needs in 7 out of 10 years. In only 3 years out of 10 would IPC expect monthly energy deficiencies to occur based upon low-water conditions. Market-based transactions of both hourly and term energy will continue to be used under deficit conditions.

Hourly Energy Purchases

The market price of hourly energy is based on the output of the marginal generation resources in the interconnected region offered for sale in the short-term. Historically, the hourly market in the WECC has been very reliable and robust, allowing hourly spot-purchases to be a viable component of the Company's short-term resource planning strategy.

Term Energy Purchases

Term energy purchases are for specific quantities of energy during specific periods of time that are typically longer than time periods for hourly energy purchases. Term energy contracts may be entered into directly with other utilities or may be established through local markets.

The New York Mercantile Exchange (NYMEX) is currently in the process of reconfiguring its electricity strategy to incorporate both futures and over-the-counter (OTC) instruments that are more flexible and address changes in the way the electricity industry does business today. The previous futures contracts traded at Palo Verde and the California-Oregon Border (COB) were recently delisted in anticipation of the new products that NYMEX plans to introduce.

An exchange serves to guarantee contracts by requiring collateral (margin) from traders for each obligation they hold. The exchange also sets standard terms for quantity, quality, and location for delivery. The mechanisms of the exchange and the futures contracts allow price discovery and push prices to a market-clearing price. Standardized futures contracts, together with options based on futures, allow buyers and sellers to manage price risk.

The current lack of NYMEX contracts limits the regional electricity market. In all likelihood, individual bilateral contracts with utilities and other generation owners will continue to be the principal source of term energy transactions for the foreseeable future.

Market Purchase Prices

Idaho Power's estimated market price during the planning period is best represented by a combination of the forward price curve and a price forecast. The forward price curve was used for the first five years of the planning period, and a price forecast was used for the remaining five years to represent the full cost of market purchases. The estimated market prices used in the IRP are shown in the *Technical Appendix*.

Gas Price Forecast

One of the primary variables affecting the costs of energy from either a simple-cycle or combined-cycle combustion turbine is the price of natural gas. Forward market prices and gas price forecasts produced by national forecasting organizations have been examined as part of the process to determine the appropriate gas prices used to estimate market prices for electricity.

IPC relies on a combination of forward market prices and the WEFA long-range forecast to estimate future gas prices for the IRP. The price forecasts which were examined are: (1) the November-adjusted 2001 WEFA Group long-range forecast of the price for natural gas delivered to electric utilities in the Mountain region, and (2) the November 2001 PIRA Energy Group forecast of prices at Sumas (a major gas trading hub serving the Western United States). The long-term gas market in the Northwest is typically thinly traded, causing forward pricing data to be less reliable.

For the year 2002, a nominal delivered price of $2.69 per MMBTU, based on forward market prices, was used in the IRP. For subsequent years, the WEFA forecast was used for the IRP.

The gas price forecast used to develop the estimate of market prices contained in this 2002 IRP is shown in the *Technical Appendix*.

Coal Price Forecast

The IRP coal price forecast is a composite of Idaho Power's spot coal forecasts for its three existing thermal plants. The plant forecasts are created using current coal and rail transportation market information and then escalated based on the 2001 WEFA long-range forecasts. The resulting $/MMBTU cost estimate represents the delivered cost of coal including rail cost, coal cost, and use taxes.

Transmission Resources

Upgrades

Adequate transmission capacity is critical to the success of a strategy that utilizes purchases from the wholesale market to supplement and optimize the IPC-owned and purchased generation resources. Transmission alternatives do not generate additional energy or capacity, but the transmission system does provide access to energy markets.

Traditionally, it has been a generally accepted proposition among electric utilities in the West that it is less expensive and faster to construct new transmission facilities than to construct new generation. However, in recent times, the regulatory analyses and other right-of-way requirements associated with new transmission facilities construction have resulted in much longer lead times and substantially higher costs for new transmission facilities when compared to prior time periods. Typically, the permitting and construction lead times are five to eight years, depending on transmission distance and the voltage level.

The costs and impacts of potential transmission upgrade alternatives are investigated as part of the IRP. The portion of the Company's transmission system that would provide the most immediate benefit would be the upgrade of the transmission lines between the Pacific Northwest region and the Boise area. Transmission construction alternatives for the Pacific Northwest lines would be significantly long (between 170 and 400 miles). Analyses of a range of transmission alternatives, including substation additions, show construction costs of approximately $400,000 to $700,000 per mile and incremental transmission costs between $45 and $90/kW per year for additional Pacific Northwest transmission connections.

The projected Pacific NW transmission upgrade costs are approximately 500 percent higher than Idaho Power's embedded transmission costs. Assuming a 50 percent annual load factor (typical for interconnections) and further assuming that all project capacity is subscribed, construction of new transmission lines results in 10 to 20 mills/kWh added to Pacific Northwest purchased energy prices. If some of the transmission capacity is unsubscribed, then the estimated transmission upgrade estimates are further increased.

Transmission upgrades across the Borah West path located west of American Falls, Idaho, are estimated to cost about $15/kW per year. Upgrades to the Borah West Path would be necessary for network resource developments east of Borah.

New Transmission Projects

Southwest Intertie Project (SWIP)

Idaho Power has obtained the necessary right-of-way permits to construct the Southwest Intertie Project, a 500-kV transmission line to connect the Company's Midpoint Substation with Southwest transmission lines at a location near Las Vegas, Nevada. Uncertainties associated with implementation of FERC Orders 888 and 2000 have halted development of the SWIP Project.

Brownlee to Oxbow 230 kV Transmission Line Number 2

To improve reliability of the Brownlee to Oxbow transmission line and increase the transfer capacity, IPC plans to build a new 10-mile, 230 kV transmission line between Brownlee and Oxbow. The project would increase Brownlee East capacity by approximately 100 MW. Idaho Power Company is presently siting the transmission facilities. The transmission upgrade is expected to cost $18 million and to be completed and in service by the fall of 2004.

Borah West Transmission Upgrade

The Borah West path is a fully-subscribed transmission path and is a known constraint within the IPC main grid transmission system. Idaho Power Supply has submitted a study request to the Idaho Power Transmission Group to determine the feasibility and cost of upgrading the Borah West transmission line and increasing the transmission capacity by 150 MW.

LaGrande Upgrade

Idaho Power Company has submitted a study request to determine the feasibility and cost of upgrading the transmission line from Brownlee to LaGrande, increasing the transmission capacity by 154 MW.

Generating Resources

Background

The following discussion of the costs associated with various non-hydro generating technologies is based on the technology descriptions, capital costs, operational and maintenance cost and heat-rate data derived from the Department of Energy/Energy Information Administration, (DOE/EIA) 2002 Annual Energy Outlook (AEO) report. The government data were combined with specific IPC financial factors, such as cost of capital, interest on funds used during construction, and tax rates, to further refine costs used for comparisons. Use of data taken from a common source like the AEO report allows Idaho Power to make a consistent first comparison of the costs of the selected technologies at generic locations. The initial cost comparison is shown in Figure 11. The fuel cost estimates are described earlier in this chapter.

Idaho Power selected several generation technologies for investigation at specific Idaho locations. The selected generation technologies were estimated using plant-sizing, capital costs, operational costs, and capacity factors that were more consistent with known and expected operational assumptions for generation within the Idaho Power service territory.

While the average load continues to increase in the Idaho Power service territory, the near-term problem is serving the peak load. Figure 4 shows that under the 70th percentile water and 70th percentile load planning scenario, the monthly energy deficiencies are expected to be less than 100 MW until December 2005. However, under the same planning scenario, peak-hour deficits exceed 200 MW in 2003, 2004 and again in 2006. The peak-hour deficiency drops below 200 MW in 2005 when Garnet comes on-line, but deficiencies exceed 200 MW in 2006 and increase to over 600 MW by 2011. The near-term requirements indicate the need for a peak-hour resource. The generation resources are ranked in Figure 11 through Figure 14.

Hydroelectric Generating Resources

Efficiency Improvement Projects

Idaho Power continually investigates and evaluates opportunities to economically improve efficiency and generating capacity at existing hydroelectric facilities. Each improvement opportunity is technically and economically considered on an individual project basis. Proposed capacity upgrades are evaluated by standards for cost effectiveness of long-term resource investments, including uncertainty in environmental impact.

New Hydro Projects

Idaho Power is proposing a significant hydro capacity upgrade at the Shoshone Falls facility. The existing Shoshone Falls Hydroelectric facility was completed in 1921 and has a generating capacity of 12.5 MW. Idaho Power is proposing a 64 MW expansion at the Shoshone Falls facility.

With the expiration of Shoshone Falls FERC License No. 2778, Idaho Power filed an application to relicense the facility in 1997. As part of the license preparation, a facility expansion was identified and investigated. At the time of license submittal, Idaho Power determined it was not economical to expand the facility. Re-examination of the facility expansion investigation following the recent energy crisis has led IPC to propose the Shoshone Falls upgrade. The Shoshone Falls upgrade must be considered within the Shoshone Falls relicensing process. If Idaho Power Company receives positive feedback concerning the proposal then IPC will begin the environmental and regulatory process involved in licensing and permitting the Shoshone Falls upgrade.

If Idaho Power does not proceed with the Shoshone Falls upgrade, there is no guarantee that the upgrade will be available for IPC customers in the future. Therefore, the project has been designated as non-deferrable.

Thermal Generating Resources

Efficiency Improvement Projects

Idaho Power Company, in conjunction with its operating partners, is continually looking for economic efficiency and capacity improvements at the thermal generation facilities. The Company is presently considering efficiency upgrades at both the Boardman and Valmy generation facilities.

Boardman

A high pressure/intermediate pressure turbine modification is being evaluated. The modification would add approximately 2.5 MW of capacity (Idaho Power would receive 10 percent of the 25 MW increase) at a levelized cost of approximately 8 mills per kWh.

Valmy

A low-pressure turbine modification is being evaluated for both Units 1 and 2. The modifications are projected to add approximately 7 MW of capacity (Idaho Power would receive 50 percent of the 14 MW increase) at a levelized cost of approximately 11 mills per kWh.

Figure 11 30-Year Nominally Levelized Cost of Production
For Economic Ranking at a Generic Location *(excluding transmission costs)*

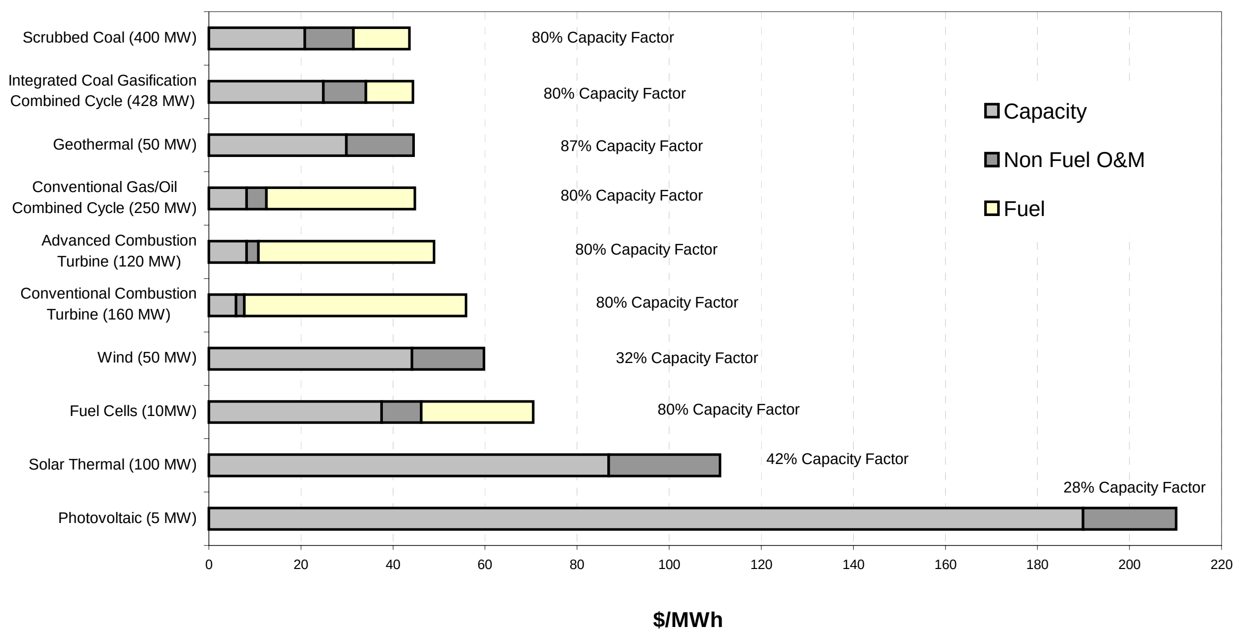


Figure 12 30-Year Nominally Levelized Cost of Production
For Economic Ranking at an Idaho Location *(excluding transmission costs)*

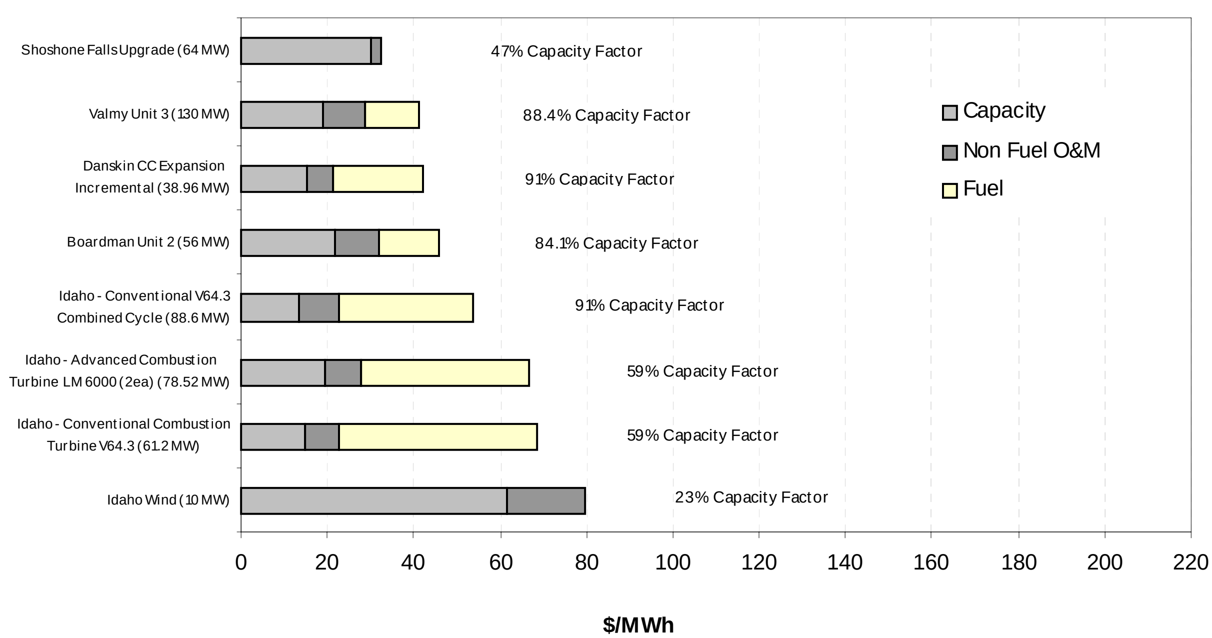


Figure 13 30-Year Nominally Levelized Fixed Costs of Operation For Economic Ranking at a Generic Location *(excluding transmission costs)*

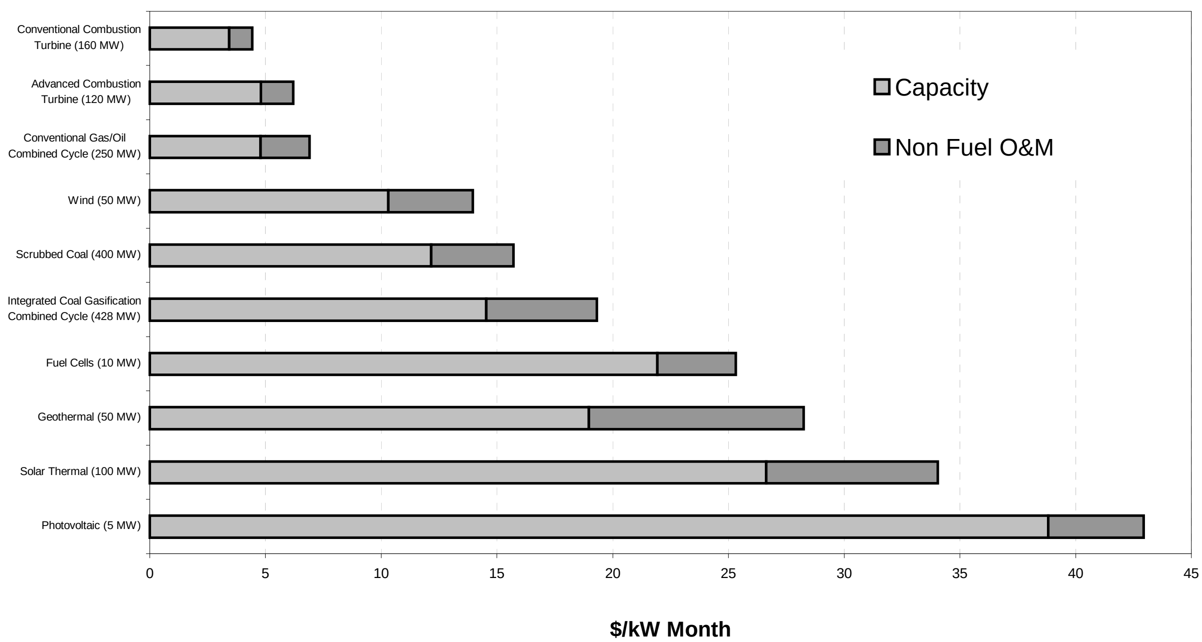
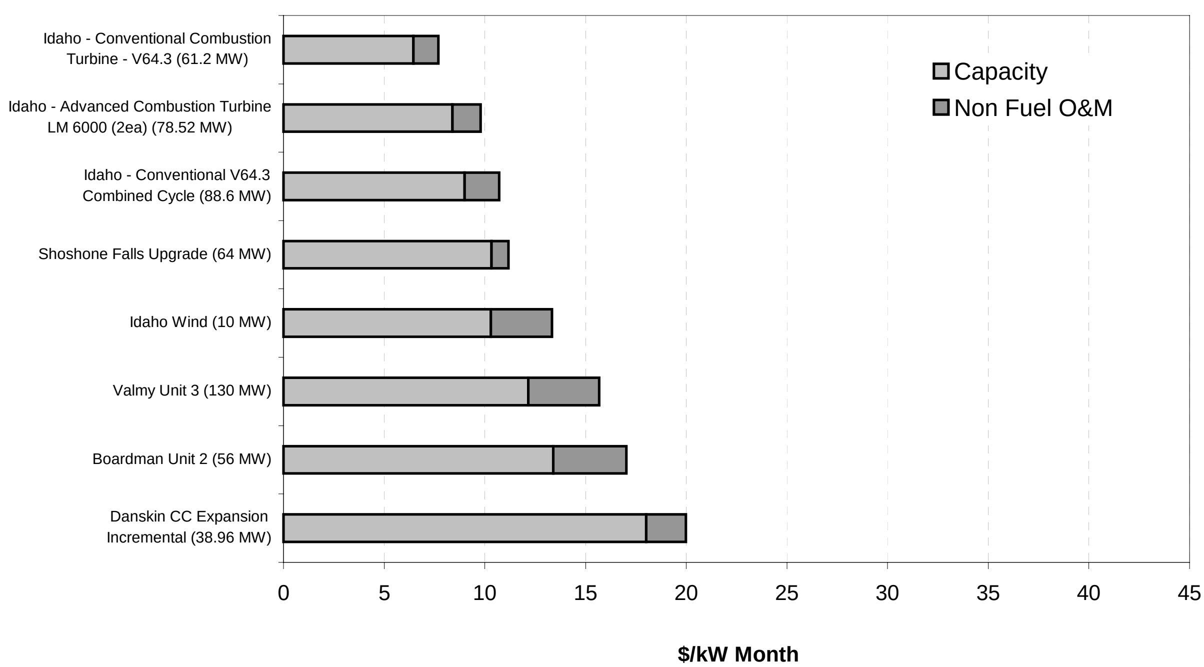


Figure 14 30-Year Nominally Levelized Fixed Costs of Operation For Economic Ranking at an Idaho Location *(excluding transmission costs)*



Thermal Technologies

Conventional Steam Turbine Plant

Conventional coal-fired steam turbine technology is well developed. The standard configuration has a conventional steam boiler generating steam, which is then used to drive a turbine to generate electricity. The emissions from the combustion of coal are treated (scrubbed) to meet applicable clean-air standards.

For a 400 MW unit, the 2002 AEO assumes a capital cost of $1,148 per kW of plant capacity. Using an 80 percent capacity factor, a levelized cost of approximately 43.6 mills per kWh at a generic location is projected (Figure 11).

Advanced Coal Technologies

The AEO uses integrated coal gasification combined-cycle technology to address the cleaner-burning coal technologies under development. The primary benefit of advanced coal technology plants is the ability to achieve lower emissions of sulfur dioxide and nitrogen oxides without the need for add-on emission control equipment.

Integrated coal gasification combined-cycle plant capital costs from the 2002 AEO were $1,373 per kW for a 428 MW plant. The derived levelized cost of generation at a generic location is approximately 44.4 mills per kWh, operating at an 80 percent capacity factor.

Simple-Cycle Combustion Turbine (SCCT)

Combustion turbines (CT), either simple-cycle or combined-cycle, burn natural gas or fuel oil distillate to create hot exhaust gas, which is allowed to expand through a turbine to turn an electric power generator. Compared to coal-fired steam plants, CTs burn more expensive fuel and typically have higher heat rates. Compared to coal-fired generation, the principal advantages of a CT are lower capital costs per kW of generating capacity and shorter lead times for siting and construction. SCCTs also have relatively lower environmental impacts than do coal-fired plants and possess the ability to more rapidly adjust the level of generation over the output range. Consequently, SCCTs are often selected for peaking and other low-capacity factor requirements. After installation, a SCCT may be converted to a combined-cycle unit for more efficient operation at higher capacity factors by adding a heat recovery boiler and steam turbine generator.

The 2002 AEO report estimates that capital costs of a 160 MW simple-cycle combustion turbine plant are $348 per MW. The levelized cost of generation at a generic location is approximately 55.9 mills per kWh, operating at an 80 percent capacity factor (Figure 11).

Idaho Power has estimated the cost of simple-cycle technology sited in Idaho. Both a conventional combustion turbine and an advanced aero-derivative combustion turbine were estimated. Both of these turbines are smaller in capacity than the 160 MW SCCT used in the AEO report. The smaller sized SCCTs were chosen because of the operating hour limitations a 160 MW plant would have under state emission regulations unless the unit was equipped with selective catalytic reduction emissions controls. Although the smaller capacity SCCTs have a higher capital cost per kW installed, the smaller size allows greater operating flexibility and a higher capacity factor.

Combined-cycle Combustion Turbine (CCCT)

The CCCT adds a heat recovery boiler and steam turbine generator to the simple-cycle combustion turbine to decrease the effective heat rate and increase overall generating efficiency. The heat recovery system uses the residual hot exhaust gas from the combustion turbine to create steam, which is then used to drive a secondary turbine to generate electricity. The increased capital cost of the CCCT, coupled with increased fuel efficiency, tends to make the CCCT more cost-effective at higher capacity factors than the SCCT.

Construction costs and operating characteristics for a new 250 MW CCCT based on the 2002 AEO show an estimated capital cost for the unit of $468 per kW of capacity. Operating at an 80 percent capacity factor, the CCCT has a levelized cost of generation at a generic location of approximately 44.8 mills per kWh (Figure 11).

Idaho Power has estimated the cost of a specific CCCT sited in Idaho in contrast to the more generic AEO cost data. The simple-cycle combustion turbine estimated in the previous section was expanded to a CCCT plant sited in Idaho.

Micro-Turbines

Micro-turbines are scaled-down versions of the larger combustion turbine generators. Micro-turbines range in size from 25 to 100 kW and are applicable to small commercial facilities, acting as either backup power sources or as generators that run in parallel with the utility system. Banks of the machines have been set up to provide power to larger commercial facilities and some industrial facilities. Micro-turbine commercialization is limited, with only a few manufacturers offering the products. At this time, there are no micro-turbine generators operating on the Idaho Power system.

Diesel and Natural Gas Internal Combustion Generators

Diesel- and gas-fueled generators are one of the most common forms of distributed electric generation. Based on the internal combustion engine, the generators provide reliable electrical service in many diverse locations. Diesel generator capacities range from a few kW to beyond 10 MW. Idaho Power owns two 2.5 MW diesel engine-generators in Salmon, Idaho, that are primarily used for backup power. Many industrial and large commercial facilities have internal combustion engine generators used for backup power. Nearly every hospital in Idaho has an emergency internal combustion engine generator.

Many diesel generators were deployed throughout the Northwest last summer when the market price of electricity made distributed diesel generation profitable to operate. When market prices returned to historical norms, use of the diesel generators declined significantly. Idaho Power’s own trial with diesel generators in the Treasure Valley in the summer of 2001 was, at best, problematic.

Advanced Technologies

Fuel Cells

Fuel cells are electrochemical devices that convert the chemical energy of a fuel, such as natural gas, into low-voltage electricity. In a typical fuel cell, hydrogen extracted from the fuel is oxidized at an anode using oxygen supplied from the cathode. Ion flow across the fuel cell is accompanied by flow of electricity through the external circuit. The by-products of the chemical process are carbon dioxide, water and heat.

Fuel cells are thought by many to be the future of distributed generation. Fuel cells are highly reliable and can provide backup power in critical facilities. The present cost for a fuel cell system is extremely high, but improvements in manufacturing and design innovation are expected to reduce fuel cell costs. Fuel cells are expected to sell commercially for $1,000 to $1,500 per kW when the systems are in production. At this time, commercial fuel cell systems are just becoming available and are limited in size from a few watts to 250 kW.

An individual fuel cell has fairly low output so multiple fuel cells are usually connected together in a battery configuration, forming power modules. The power modules are then combined to meet the power application requirement.

The fuel cell technology selected in the 2002 AEO for cost projection purposes was a 10 MW molten carbonate system. A 2 MW molten carbonate demonstration unit was built and operated in Santa Clara, California. The unit was a limited success and operated for several months on a restricted basis during 1996.

The AEO capital assumption is $2,145 per kW for fuel cells. The resulting levelized cost of generation at a generic location is about 70 mills per kWh, operating at an 80 percent capacity factor (Figure 11).

Biomass

Production of power from biomass has declined in Idaho Power's service territory in the past few years due to the closing of Boise's (formerly Boise Cascade) Emmett lumber mill. However, interest in using animal waste or municipal sewage to produce methane for power production is increasing, and IPC anticipates that some farms and feedlots may bring anaerobic digesters on-line during the IRP planning period.

Solar Photovoltaic

The cost of photovoltaics (PV) has decreased significantly in the past decade, even though PV cost is still quite high when compared to conventional generation. In some regions of the country with high utility costs, there has been some PV capacity installed in the last few years. Photovoltaic generation continues to be used in remote off-grid locations.

The building block of the solar photovoltaic (PV) system is a solid-state solar cell that converts solar radiation directly into electrical energy. A number of solar cells are interconnected to form a solar module. PV systems range in size from small, single-module systems to large systems with many hundreds of solar modules.

The 2002 AEO uses a capital cost of $3,931 per kW for a 5 MW station with a 28 percent capacity factor. The cost estimate yields a levelized cost of about 210.1 mills per kWh for generation at a generic location (Figure 11).

Solar Thermal Generation

Solar thermal power plants convert solar energy to electricity by concentrating sunlight to produce heat and then electricity. The systems are similar to typical generating plants in that the heat is converted into electricity via a turbine generator using conventional steam-cycle technology.

Idaho Power participated in the Solar Two demonstration project near Barstow, California, along with several other utilities and government agencies. The 10 MW Solar Two demonstration project is now over.

The 2002 AEO uses a capital cost of $2,605 per kW for a 100 MW station at a generic location yielding a levelized cost of approximately 111.0 mills per kWh at a 42 percent capacity factor (Figure 11).

Windpower

Most wind generation being installed today is in the form of large wind farms where multiple wind turbines are placed at one site and the aggregate power is delivered to the electric grid. Wind generation facilities range in size from 10 MW to over 100 MW. Additionally, a few companies market small, home-sized wind turbine generators, although the cost of the small generators remains high. Some companies are also trying to market used, mid-sized wind turbines. Mid-size wind turbines range in size from 25 kW to 200 kW and would be applicable to large residences and farms.

Wind turbines currently being deployed have improved aerodynamics, are less costly, and more reliable than earlier versions. Using 2002 AEO capital costs of $1,008 per kW, the levelized cost at a generic location would be approximately 59.7 mills per kWh for a 50 MW wind plant having a 32 percent capacity factor (Figure 11).

Because the wind intensity at a given location is inconsistent, the energy produced from wind turbines is less useful than energy produced from resources that can be dispatched to meet system load requirements. However, due to the generation and storage flexibility of Idaho Power's hydroelectric system, a moderately-sized wind project may be feasible as part of the generation portfolio.

Idaho Power believes it would be prudent to pursue a pilot wind generation project to more accurately define the costs and benefits of such a project. If the pilot project meets acceptable goals for costs and benefits, then the project could be expanded at a later date, contingent upon continued public support and Commission approval.

Geothermal

Geothermal power plants convert geothermal heat to electricity by using the earth's heat to produce steam, which is then used to drive a steam turbine. The technology has always produced some interest because of the potential low-cost electricity that could be produced at a high-quality geothermal field.

Because of the remote locations and relatively low temperature, the known geothermal areas within Idaho Power's service territory have limited potential. The 2002 AEO cost and performance data represent the best site that could be developed in the Pacific Northwest. An optimal location yields a 50 MW project with costs of $1,791 per kW, a levelized cost of approximately 44.5 mills per kWh and an 87 percent capacity factor (Figure 11). It must be noted that the AEO data do not assume any cost for the use of geothermal fluid.

In addition, the AEO data do not include the exploration and development cost of the geothermal resource, nor are the costs of purchasing geothermal fluid from the owner of the resource considered. The AEO cost information assumes that the geothermal fluid resource exists and can be utilized at zero cost. In most cases, the royalty cost of geothermal fluid would be significant.

Energy Storage

An effective energy storage system could enhance existing generation and transmission resources. Presently, energy storage systems with a capacity greater than 1 MW are limited to pumped storage, hydroelectric generation, and compressed air technologies. Each technology is site-specific. The operating flexibility of the existing Idaho Power hydro system already provides a significant amount of energy storage.

Distributed Generation

The term “Distributed Generation” (DG) refers to small- or intermediate-sized generation resources typically placed near the load. DG ranges in size from less than a kW up through 50 MW and beyond.

Distributed generators are commonly operated as stand-alone units. Distributed generation is usually not operated for the benefit of the entire power system, but for the benefit of the individual DG operators.

Idaho Power Company currently purchases approximately 100 average megawatts of energy generated by 68 different cogeneration and small power producers (CSPP). These CSPP projects are small (20 kW to 9 MW) and are distributed throughout the Idaho Power Company service territory. In response to news of higher wholesale electric prices and longer contract terms, the Company has received numerous inquiries from potential developers requesting information concerning the appropriate interconnection processes and the various contract options available for new DG projects.

Solar, wind, small hydro, wood waste, methane (animal waste, landfill gas, waste water treatment plants), and geothermal are some of the various fuel sources that are being considered by various distributed generation plant developers.

In negotiating a contract with a potential developer of distributed generation, Idaho Power Company adheres to Federal and State regulations and considers the benefits of the project's physical location, dependability, flexibility and any other characteristics that may influence the value of the energy to the Idaho Power Company system. A report outlining the role that distributed generation could play in Idaho Power’s future resource portfolio was filed with the Oregon Public Utility Commission in January 2002. A copy of the report can be found in the *Technical Appendix*.

Small Hydro

Small, or low-head hydro facilities are installed throughout the IPC service territory. The extensive system of irrigation canals is ideally suited to small hydro applications. Developers continue to propose new hydroelectric projects on Idaho’s many irrigation canals. Most of the recently proposed projects are under 1 MW in size. Each small hydro project is analyzed individually for financial feasibility. Successful small hydro applications are limited due to high capital costs, the seasonal nature of canal flows, and existing market prices for energy.

Demand-Side Measures and Pricing Options

Demand-side measures and energy conservation measures are often seen as synonymous. Unfortunately, generic energy conservation programs are unlikely to be sufficient to meet the peak deficiencies facing Idaho Power during the term of this resource plan. Demand-side measures and pricing options that target peak-hour demand reduction are more likely to address

Table 5 Idaho Power Company

Externality Cost Adder Ranges for Thermal Plant Emissions

	Combinations of NOx, TSP and CO_2 Adder Levels in Dollars per Ton					
Emission	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6
NOx	$2,640	$2,640	$2,640	$6,600	$6,600	$6,600
TSP	$2,640	$2,640	$2,640	$5,280	$5,280	$5,280
CO_2	$13.20	$33.00	$52.80	$13.20	$33.00	$52.80

the peak deficiencies facing Idaho Power Company.

Power generation costs vary hour by hour depending on a variety of factors including aggregate demand and the availability of generation resources. Economic theory indicates that accurate prices are necessary for an efficient allocation of resources. Accurate price signals for electricity are based on market conditions, reflect the true production and distribution costs of service, and vary depending on the aggregate demand and availability of generation resources.

Idaho Power Company implemented a Time-of-Use Pilot Program for irrigation customers in April 2001. The purpose of the Pilot Program is to gather meaningful information regarding irrigation customers' ability to shift energy consumption from higher-cost peak hours to lower-cost off-peak periods. The data collected during the pilot program is expected to provide Idaho Power Company, the customers of Idaho Power, and the Idaho PUC with the information necessary to evaluate the impacts costs, and benefits of time-of-use pricing. The irrigation pilot program continues until October 1, 2002. Idaho Power Company will analyze the pilot program's impact after the program data becomes available in late 2002.

Idaho Power Company's Voluntary Irrigation Load Reduction program was very effective in reducing summer demand during 2001. Similar demand-side measures targeting peak reduction may also be effective.

Due to the nature and timing of the projected peak deficits and transmission overloads, conservation, demand-side measures, and pricing options must be carefully designed and targeted to cost-effectively address the projected deficits.

Societal Costs

All electric power resources have costs, benefits, and impacts beyond the construction and operating costs that are included in the price of electricity. The non-internalized costs include the air pollution and natural resource depletion associated with thermal generation, the effects on aquatic life and recreation associated with hydroelectric dams, and the aesthetic and bird mortality impact associated with renewable wind power.

Order 93-695 from the Oregon Public Utility Commission specified cost adders associated with the level of sulfur dioxide (SO_2), carbon dioxide (CO_2), nitrogen oxides (NOx), and total suspended particulate (TSP) emissions from new thermal generating plants. SO_2 emission costs are included in the calculation of direct utility costs through modeling of the emission allowance system established by the Clean Air Act. The sensitivity of the choice of least cost adders for CO_2, NOx and TSP emissions has been investigated for the six levels of cost adders specified by the OPUC in Order 93-695.

Table 5 shows the six specified combinations of externality cost adders for CO_2, NOx and TSP emissions. Each emission has been assigned a low- and a high-level of cost adder, and the different possible combinations of cost adders for the individual emissions represent the range of total emission cost adders. The low end of the range is produced by the low adder values for each emission, and the high end of the range by the high adders for each emission.

6. Ten-Year Resource Plan

Overview

Development of the ten-year resource plan involves the selection of resources from Idaho Power's future resource options (described in Chapter 5) that are well-suited to meet the forecasted deficiencies identified in Chapter 4. Idaho Power has selected four strategies to analyze as the Company's 2002 resource plan. A cost comparison of the resource strategies was used to determine the single strategy that is most likely to meet expected loads at the lowest expected cost. The four strategies were also analyzed in the context of their relative sensitivity to various uncertainties. Uncertainties included external cost adders for emissions from thermal generation and discount rate variations. The result of the analytical comparisons led to the selection of Idaho Power's 10-year resource plan.

Unless noted otherwise in this section, references to forecasted energy surpluses or deficiencies are based on a 70^{th} percentile stream flow and 70^{th} percentile load-planning criterion. Peak-hour deficiencies and transmission overloads are based on a 90^{th} percentile stream flow and 70^{th} percentile load-planning criterion.

Each of the four strategies selected for evaluation in the 2002 Integrated Resource Plan assumes that the Garnet Power Purchase Agreement is approved and that the Garnet Energy Facility is capable of providing energy and capacity in June 2005. If the Garnet Power Purchase Agreement is not approved, or if the facility is not constructed for any reason, Idaho Power will need to replace the energy and capacity that Garnet is expected to provide. If Garnet were canceled, Idaho Power would most likely combine the projected deficiencies currently identified in this IRP with the additional deficits created by canceling Garnet, and reassess the options available for supplying the combined deficiency.

In addition, the 2000 IRP assumed a continuation of seasonal market purchases from the Pacific Northwest during the entire planning period. The seasonal purchases consisted of 250 aMW of energy during July and August and 200 aMW of energy during November and December. The addition of the 90 MW Evander Andrews Power Complex in 2001, combined with changes in the load forecast, have permitted Idaho Power to reduce the planned seasonal purchases that were assumed in the 2000 IRP. However, all of the resource strategies considered in the 2002 IRP include some level of market purchases.

Resource Strategies

The first resource strategy considered is a long-term limited quantity market purchase strategy.

The second resource strategy considered is a combination of long-term market purchases of varying quantities and a 64 MW facility upgrade to the existing Shoshone Falls hydro plant.

The third strategy considered is a combination of short-term limited-quantity market purchases, the addition of a new 200 MW peaking resource and a 64 MW facility upgrade at Shoshone Falls.

The fourth resource strategy considered is a combination of long-term limited-quantity market purchases, the addition of a new 100 MW peaking resource, and a 64 MW facility upgrade at Shoshone Falls.

Three of the four resource strategies include the Shoshone Falls upgrade. The actual increase in output at Shoshone Falls will vary by month and will be determined by water conditions. An average increase in output of 30 MW was used in the energy analysis, although the amount varies by month. During median water conditions, the Shoshone Falls upgrade will provide 33 aMW, and, under 70th percentile water conditions, the Shoshone Falls upgrade will provide 16 aMW. Peak nameplate generation from the Shoshone Falls upgrade is expected to be 64 MW.

As noted earlier in this plan, Idaho Power is proposing to pursue the Shoshone Falls upgrade as a non-deferrable project. The levelized cost of energy from the upgrade project is shown in Figure 12. Energy produced from the Shoshone Falls upgrade is competitive when the Shoshone Falls levelized costs are compared to the costs of the other resources shown in Figure 12. Considering levelized cost, and the fact that the project increases the efficiency and output of an existing hydro project, Idaho Power plans to proceed with the upgrade. Idaho Power does not anticipate permitting or environmental issues to adversely affect the Shoshone Falls upgrade.

The four resource strategies are outlined in Table 6.

Strategy 1

The first resource strategy considered is a long-term limited quantity market purchase of energy and capacity. The strategy includes long-term market purchases of 100 MW during June, July, November and December in years 2002 through 2011. While the strategy is similar to the market purchase strategy included in the 2000 IRP, the magnitude of the purchases is significantly less than the 200 MW to 250 MW considered in 2000.

Strategy 1 is capable of supplying projected energy needs through November of 2005. In Strategy 1, peak-hour transmission overloads from the Pacific Northwest in excess of 100 MW occur in July of 2003, July 2004, and again in July 2006. Strategy 1 is an alternative for meeting forecast energy deficiencies in the near term. In Strategy 1, the decision to add additional resources, including the Shoshone Falls upgrade, is deferred until the next IRP, or an interim assessment.

Table 6 Resource Strategies

Strategy	Years	Quantity	Description
1	2002-11	100 MW	Term Market purchase in June, July, November and December; sources include NW, SE, NE and/or Garnet during non-contract months. Reassess deficiency in 2004 IRP.
2	2002-04	100 MW	Term Market purchase in June, July, November and December; sources include NW, SE, and NE. Reassess deficiency in 2004 IRP.
	2005-11	200 MW	Term Market purchase in June, July, November and December.
	2007-11	30 aMW	Shoshone Falls upgrade
3	2002-04	100 MW	Term market purchase in June, July, November and December; sources include NW, SE, and NE.
	2005-11	200 MW	Peaking resource (simple-cycle CT or equivalent)
	2007-11	30 aMW	Shoshone Falls upgrade
4	2002-04	100 MW	Term market purchase in June, July, November and December; sources include NW, SE, and NE.
	2005-11	100 MW	Peaking resource (simple-cycle CT or equivalent)
	2005-11	100 MW	Term Market purchases in June, July, November and December.
	2007-11	30 aMW	Shoshone Falls upgrade

Strategy 2

The second resource strategy utilizes a combination of market purchases of varying quantities and the Shoshone Falls upgrade. Like Strategy 1, the second strategy includes long-term market purchases of 100 MW during June, July, November and December from 2002 through 2004. Beginning in 2005, the market purchases increase to 200 MW in the same months. The final component of the second resource strategy is the Shoshone Falls upgrade, which is expected to be available in 2007. Under Strategy 2, a peak-hour transmission overload from the Pacific Northwest in excess of 100 MW is forecast in July 2003, July 2004, and again in July 2006 – the same as Strategy 1. From an energy perspective, the second resource strategy is capable of meeting monthly energy deficiencies through July of 2009. Although the second strategy offers enhanced reliability and a reasonably low cost for meeting the monthly energy deficiencies, peak-hour deficiencies and transmission overloads are still present.

Strategy 3

The third resource strategy considered is a combination of short-term market purchases, a 200 MW peaking resource and the Shoshone Falls upgrade. In the third strategy, the market purchases are short-term, providing a bridge until Garnet capacity is available in 2005. Strategy 3 adds a 200 MW peaking resource in 2005 and the Shoshone Falls upgrade in 2007. The third strategy assumes that the peaking resource is located between the Brownlee

East and Borah West constraints, thereby reducing the need to transmit power across those constraints.

The Strategy 3 combination of resources is capable of meeting monthly energy deficiencies through October of 2009. Under Strategy 3, peak-hour transmission overloads from the Pacific Northwest in excess of 100 MW occur in July 2003, July 2004, and again in July 2008. Under expected market prices, Strategy 2 is less expensive that Strategy 3. However, under the high market price scenario, Strategy 2 is more expensive for two reasons – first, purchases are being made at a higher price and, second, there is no peaking resource available to make profitable surplus sales when market prices are high. The addition of a peaking resource in Strategy 3 provides increased reliability, security and an opportunity to generate profitable surplus sales during times of high market prices or when not needed for system load during the later portion of the planning period.

Strategy 4

The fourth resource strategy is a combination of long-term market purchases, a 100 MW peaking resource and the Shoshone Falls upgrade. The fourth strategy is very similar to Strategy 3; however, instead of adding a 200 MW peaking resource in 2005, Strategy 4 adds a 100 MW peaking resource and 100 MW of market purchase in 2005. The net effect is substituting 100 MW of peaking resource for 100 MW of market purchase. The combination of resources in Strategy 4 is capable of meeting monthly energy deficiencies through August of 2009. Peak-hour transmission overloads from the Pacific Northwest in excess of 100 MW occur in July 2003, July 2004, and again in July 2007. Under expected market prices, the cost of Strategy 4 is between the costs of Strategies 2 and 3.

The fourth resource strategy balances market purchases with the addition of 100 MW internal generation. During times of high market prices, there is less generation available to produce profitable surplus sales than is available under Strategy 3. Conversely, under low market prices, Strategy 4 is preferable to Strategy 3 because of less-expensive market purchases and lower fixed costs associated with a smaller peaking resource in Strategy 4.

Cost Comparison of Resource Strategies Including Emission Cost Adders

A cost analysis was performed for each of the four resource strategies with the emission adders identified in OPUC Order 93-695. Cost estimates of the generating resources assumed a 30-year operating life; the results are summarized in Table 7. As shown in Table 7, Strategy 1 is the lowest cost and Strategy 3 is the most expensive. The relative ordering of the strategies is the same for Zero, Level 1 or Level 6 emission adders.

Table 7 Cost Comparison of Resource Strategies
Over the Range of Emission Cost Adders Assuming Expected Market Prices
($ Millions)

Resource Strategy	10 Year Plan with Emission Adders		
	Zero	Level 1	Level 6
Strategy 1 – LT Market Purchase (MP)	43	99	243
Strategy 2 – LT MP, Shoshone Falls upgrade	94	151	295
Strategy 3 – ST MP, 200 MW Peaking Resource plus Shoshone Falls upgrade	146	203	347
Strategy 4 – LT MP, 100 MW Peaking Resource plus Shoshone Falls upgrade	129	185	329

To meet Idaho Power Company's projected deficiencies and generate profitable surplus sales when market prices permit, the peaking resources and Shoshone Falls upgrade were dispatched against an expected market price. Capacity factors for the peaking resources varied from nearly zero under the low-price scenario to full load under the high-price scenario. The market purchase strategy was quantified using a combination of forward prices at Mid-Columbia (Mid-C) for the first five years and a Northwest market price forecast for the last 5 years of the planning period. The costs of the resource plan for each strategy are progressively increased by the costs of the minimum applicable emission adders.

Discount Rate

The discount rate used to determine the present value of the future costs of potential resources can influence which of the resources are chosen for the plan. A high discount rate tends to favor resources having low initial investment cost, but high future operating costs such as gas-fired generation. A low discount rate tends to favor resources with high investment costs but low operating costs, such as hydroelectric generation. Low discount rates tend to favor resources with a high percentage of total costs occurring in the early years of the resource life.

Idaho Power's after-tax weighted average cost of capital (WACC) was used as the discount rate for determining resource plan costs in the 2002 IRP. The current after-tax WACC value is 7.6 percent. Other discount rates are sometimes proposed to reflect other risks or costs considered appropriate for resource planning. For example, a lower discount rate can be used as a societal rate to emphasize the long-term costs to society of nonrenewable energy resource depletion. Conversely, a risk premium may be added to an after-tax WACC to reflect higher than normal risk, such as that inherent in making long-term resource acquisition commitments.

The sensitivity of the resource strategies to different WACC/discount rates has been investigated over a range of rates from 5.6 percent to 9.6 percent. The resulting range of present value costs for the resource strategies is shown in Table 8. The values presented are influenced not only by the varying discount rates but also by the

Table 8 Cost Comparison of Resource Strategies
Over a Range of Discount Rates Assuming Expected Market Prices
($ Millions)

Resource Strategy	Discount Rate		
	5.6%	7.6%	9.6%
Strategy 1 – LT Market Purchase (MP)	49	43	38
Strategy 2 – LT MP, Shoshone Falls upgrade	101	94	88
Strategy 3 – ST MP, 200 MW Peaking Resource plus Shoshone Falls upgrade	140	146	149
Strategy 4 – LT MP, 100 MW Peaking Resource plus Shoshone Falls upgrade	130	129	126

associated financing cost assumptions. Higher financing costs will be offset to a degree by the higher WACC and the higher corresponding discount rates. Conversely, strategies with lower-cost financing assumptions will be discounted to a lesser degree when determining the present value cost.

Although the present value measurement of resource plan costs are sensitive to the discount rate assumptions, the discount rate effects over the range of discount rates analyzed were insufficient to influence the final selection of a resource strategy.

Strategy Selection

Table 9 provides a summary of the net present value of the costs associated with each of the four resource strategies under three different market price scenarios - low, expected and high.

It is important to note that Strategy 1 is not equal to the others in terms of resources added or deficiency covered, so the lowest cost strategy is not necessarily the preferred choice. Details of the financial analysis are outlined below.

First, for the generation resources (Shoshone Falls and the peaking resource) the financial analysis utilized the levelized costs shown in Figure 12 and Figure 14. The peaking resources were assumed to be simple-cycle combustion turbines. The costs associated with two peaking facilities were derived from the estimated $/kW costs, shown in Figure 14, for the conventional combustion turbine unit located in Idaho, and then increasing the size to either 100 MW or 200 MW. The size choices are not exact and are not based on a specific turbine or grouping of turbines. In Strategies 3 and 4, final sizing of the peaking resource would be determined during the project design phase.

Since the peaking resources are long-lived assets with a service life extending beyond the planning period, a terminal value was assigned to each resource strategy to account for remaining asset life at the end of the planning period.

Based on the input received from the state commissions and the public during the last year, there is an expressed interest in Idaho Power becoming more energy-independent by reducing the reliance on market purchases, especially at high prices,

Table 9 10-Year Plan Costs with Market Sales

	Low Market Prices	Expected Market Prices	High Market Prices
Strategy 1	$28,000,000	$43,000,000	$86,000,000
Strategy 2	$76,000,000	$94,000,000	$148,000,000
Strategy 3	$208,000,000	$146,000,000	-$219,000,000
Strategy 4	$143,000,000	$129,000,000	-$6,000,000

and moving away from the median stream-flow planning criterion. Another concern is that Idaho Power should own generation assets, thereby providing customers an opportunity to receive the benefits of any profitable surplus sales through the power cost adjustment (PCA) mechanism. Idaho Power Company customers have also expressed an interest in conservation and green resource development. The public also recognizes that the regional market independence and improved reliability provided by additional generation resources come with a cost.

Strategy 1, the market purchase strategy, was eliminated from further consideration primarily because it is not a viable long-term solution under the 70th percentile planning criterion. In essence, the market purchase strategy defers the decision to add additional resources until the next IRP.

Under the 70th percentile planning criterion, additional resources or transmission is inevitable. Even under a median water planning criterion, peak-hour transmission overloads from the Pacific Northwest are forecast in 2006.

Considering the number of issues associated with siting a generation facility, Idaho Power prefers to begin resource acquisition sooner, rather that later. If the decision is deferred until the 2004 IRP, at least two years of valuable time is lost which may compromise system reliability.

While the market purchase strategy has the lowest cost of the four under several price scenarios, the market purchase does not cover the same amount of deficiency that the other strategies do. Furthermore, the market purchase strategy does not increase reliability, initiate the process for future generation resources, eliminate forecast transmission overloads or significantly reduce price risk for IPC customers.

Strategy 2 is a combination of market purchases and the Shoshone Falls upgrade. Except for the addition of the Shoshone Falls upgrade, Strategy 2 is primarily a market-based solution. Under expected market prices, Strategy 2 is $52M less expensive than Strategy 3. Under the low-price scenario, Strategy 2 is about $48M less expensive than Strategy 3. However, when the high-price scenario is considered, Strategy 2 is about $367M more expensive than Strategy 3. The high-priced market purchases made under Strategy 2 and the profitable surplus sales during non-deficit months from the Strategy 3 peaking resource create the $367M difference.

Strategy 3 considers a combination of short-term market purchases, the addition of 200 MW of capacity and the Shoshone Falls upgrade. Strategy 3 eliminates transmission overloads from the Pacific Northwest until June of 2007.

Beginning in July 2007, the projected transmission overloads from the

Pacific Northwest increase from 41 MW in 2007 to 336 MW in July 2011. The addition of 200 MW of capacity between the Brownlee East and Borah West constraints provides a significant improvement in reliability, and reduces Idaho Power's dependence on market purchases. Table 9 shows the costs associated with Strategy 3. The total cost for Strategy 3 ranges from a cost of $208M under the low-price scenario to a $219M cost savings under the high-price scenario. Under the expected market price scenario, the expected cost is $146M.

The potential benefits of internal generation under the high-price scenario are significant. When Strategy 3 is compared to Strategy 4, the benefits of internal generation under the high prices become apparent.

Strategy 4 considers a combination of long-term market purchases, the addition of 100 MW of capacity, and the Shoshone Falls upgrade. However, instead of adding 200 MW of capacity, Strategy 4 adds 100 MW of capacity and 100 MW of firm market purchases. The net effect is substituting 100 MW of capacity for 100 MW of firm long-term market purchase.

The total cost for Strategy 4 ranges from a cost of $143M under the low-price scenario to a $6M savings under the high-price scenario. Under the expected market price scenario, the expected cost is $129M - about $18M less expensive than Strategy 3. However, under the high-price scenario, Strategy 3 generates an extra $213M in savings due to profitable surplus sales of the additional 100 MW from the peaking resource during non-deficit months and avoids high-priced market purchases.

Price Probability and Strategy Selection

Of the four strategies investigated, there is no clearly-defined optimum choice. Each strategy has advantages and disadvantages. It is very difficult to determine a least-cost strategy given the uncertainty in market prices; different market prices lead to different strategies.

To further analyze the strategies, probabilities were assigned to each of the three market scenarios considered. Since price is unknown, the high-price and the low-price scenario were both assumed to have an equal probability of occurrence. The probability distribution in each price scenario was assumed to be symmetric around the expected price. For example, the probability of the low-price scenario occurring is 5%; the probability of the high-price scenario occurring is 5%, and the probability of the expected-price scenario occurring is 90%.

The estimated costs under each price scenario were then multiplied by the assigned probabilities and summed to calculate a probability-weighted cost for each scenario. It was further assumed that each price scenario was equally likely to occur. It is assumed to be equally likely for the distribution to be 1-98-1 (low, expected, high) as it is to be 20-60-20. In all of the price scenarios considered, it is assumed that, in the long run, prices will be closer to the expected price scenario. The price scenarios ranged from 0-100-0 to 20-60-20 in which the costs were calculated for each of the three resource strategies under the differing price probabilities. The costs for each strategy were summed over the various price distribution probabilities to identify the preferred choice.

For price distribution probabilities between 0-100-0 and 20-60-20, Strategy 2 is the least cost. However, Strategy 2 does nothing to increase reliability or to reduce market purchases.

For all price distribution probabilities between 0-100-0 and 19-62-19, Strategy 4 is less expensive than Strategy 3. If the low-or high-price scenarios receive weights of 20 percent or greater, then Strategy 3 is preferred over Strategy 4. The greater the likelihood of high market prices, the better it is to have a generation resource to avoid high-priced market purchases and make profitable surplus sales when the resource is not needed to support native load.

Least-Cost Resource Plan

As noted above, given the uncertainty in market prices, it is difficult to identify a least-cost plan because the assessment of least cost is dependent on the probabilities assigned to the low-, expected- and high-market price scenarios.

While Idaho Power can plan to have sufficient resources to meet the monthly average energy requirements, it is apparent that projected peak-hour loads, and, ultimately, peak-hour transmission overloads, will drive the need for additional internal generation and targeted demand-side measures that focus on peak reduction. It is appropriate to consider the duration of the expected peak-hour loads and the transmission overloads from the Pacific Northwest. While the magnitude of the transmission overloads is significant, the number of hours that the overloads are projected to occur is limited.

Before implementation of Strategy 4 or the Brownlee to Oxbow Number 2 transmission line project, the projected total number of Pacific Northwest transmission overload hours estimated under the 90th percentile water and 70th percentile load scenario range from 13 hours in 2003 to 114 hours in 2011 – a total of 402 expected hours over the planning period (see Figure 10). Under a 70th percentile water and 70th percentile load scenario, 289 hours of transmission overload from the Pacific Northwest are estimated (see Figure 9). The limited duration of the overloads illustrates the needle-peak nature of serving the last increment of load.

Because of the nature of the forecast peak load conditions, Idaho Power has identified a blended strategy to meet the resource needs. Idaho Power believes that the following plan, which outlines a balanced approach, has a high probability of being the least cost for Idaho Power's customers.

The plan is based on Strategy 4, a combination of market purchases and generation additions, and includes a transmission upgrade together with an investigation into demand reduction measures that are suitable to address the short duration of projected transmission overloads.

First, Idaho Power Company plans to continue to make seasonal market purchases of 100 aMW in the months of June, July, November and December throughout the planning period.

Second, Idaho Power Company plans to integrate demand-side measures where economically feasible, to address the short duration peaks of the system load.

Third, Idaho Power Company plans to solicit proposals and initiate the siting and permitting for approximately 100 MW of a utility owned and operated peaking resource to be available beginning in 2005.

Fourth, assuming the Idaho PUC approves the Garnet Power Purchase Agreement, Idaho Power will purchase up to 250 MW of capacity and associated energy during periods of peak need beginning June 1, 2005.

Fifth, Idaho Power Company plans to proceed with the Brownlee to Oxbow transmission line, expecting the project to be in service in 2005, increasing the import capabilities from the Pacific Northwest.

Sixth, Idaho Power Company plans to proceed with the Shoshone Falls upgrade project, expecting the upgrade to be in service in 2007.

Finally, Idaho Power Company plans to informally reassess the deficiencies that remain in 2008 though 2011 prior to 2004. The deficiencies will be formally assessed in the 2004 IRP.

A blend of supply-side resources and demand reduction measures has distinct advantages for Idaho Power customers. However, the issue of customer funding for DSM must be resolved for further progress to be made. Idaho Power is committed to cost effective demand-side management measures so long as the funding is available prior to initiating the measures

Under the 70th percentile stream flow and 70th percentile load planning criteria, the strategy outlined above is expected to eliminate energy deficiencies through August 2009 (assuming the peaking resource is in place by 2005).

Under the 90th percentile stream flow and 70th percentile load planning criteria, peak-hour transmission overloads from the Pacific Northwest in excess of 100 MW occur in July 2003, July 2004, and again in July 2008. No credit has been assumed for demand-side measures.

Figure 15 shows the monthly energy surplus/deficiencies for the 10-year planning period, assuming that the proposed plan is implemented under 70th percentile water and load conditions. Figure 16 shows monthly peak-hour surplus/deficiency under 90th percentile water and 70th percentile load conditions. Figure 17 shows the monthly peak-hour transmission deficiency from the Pacific Northwest under the same conditions.

Impacts on Rates

Impacts on customer's rates are derived from changes in capital investments and expenses. Generally, a \$10 million increase in the Company's total system rate base results in a general rate increase of 0.3 percent, while a \$10 million increase in expenditures results in a rate increase of approximately 1.8 percent.

The least-cost resource plan in the 2002 IRP proposes increases in both physical plant and purchase power expenditures from 2002-2011. As previously mentioned, the plan calls for a peaking resource in 2005, a hydro plant upgrade in 2007, and market purchases throughout the planning period.

Considering investments only and excluding associated expenses, the addition of a 100 MW peaking resource (\$89 million) and the Shoshone Falls upgrade (\$41 million) would result in a capital investment of approximately \$130 million, or a 3.9 percent rate increase.

The least-cost plan also calls for purchase power expenses totaling \$54 million (at forecasted market prices), or a 9.7 percent rate increase. As a result, an overall rate increase of approximately 13.6 percent over the planning period can be estimated for the proposed least-cost resource plan.

Actual rate impacts would not take place until the new resources are on-line, or annually, when market purchases were made. However, it is important to recognize that if power is purchased based on meeting loads under a 70th percentile water and load conditions and actual conditions turn out to be more favorable than the 70th percentile, any surplus energy would be sold and the sale proceeds would be handled via the PCA mechanism, helping reduce rates.

Figure 15 Monthly Energy Surplus / Deficiency
70th Percentile Water and Load, Strategy 4 Resources with Garnet

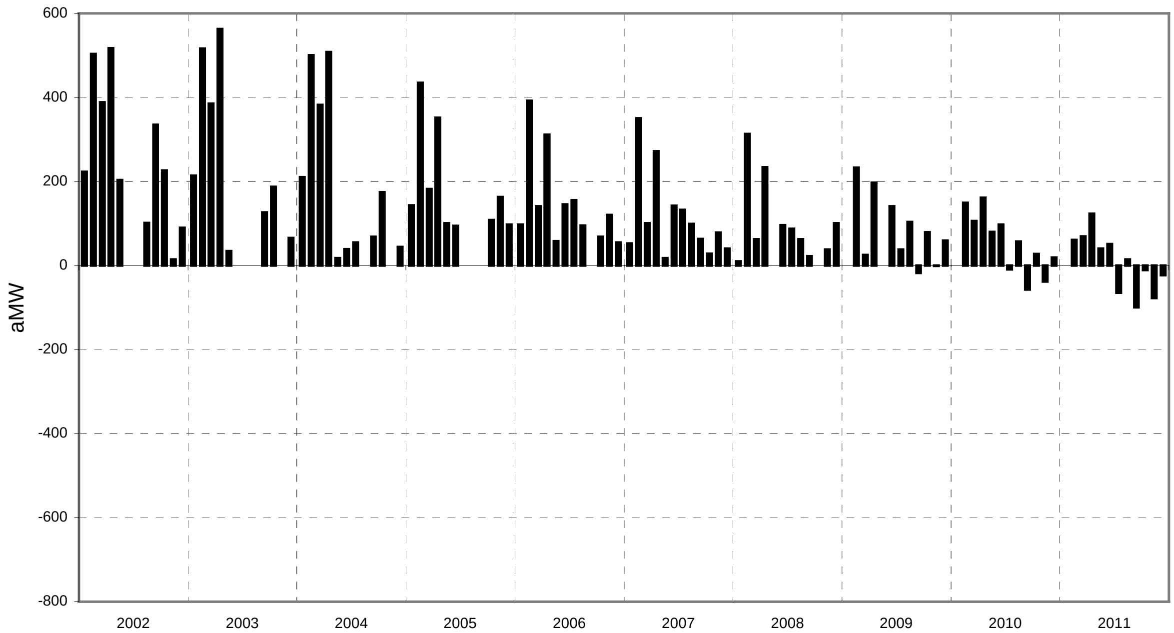


Figure 16 Monthly Peak-hour Surplus / Deficiency
90th Percentile Water, 70th Percentile Load, Strategy 4 Resources with Garnet

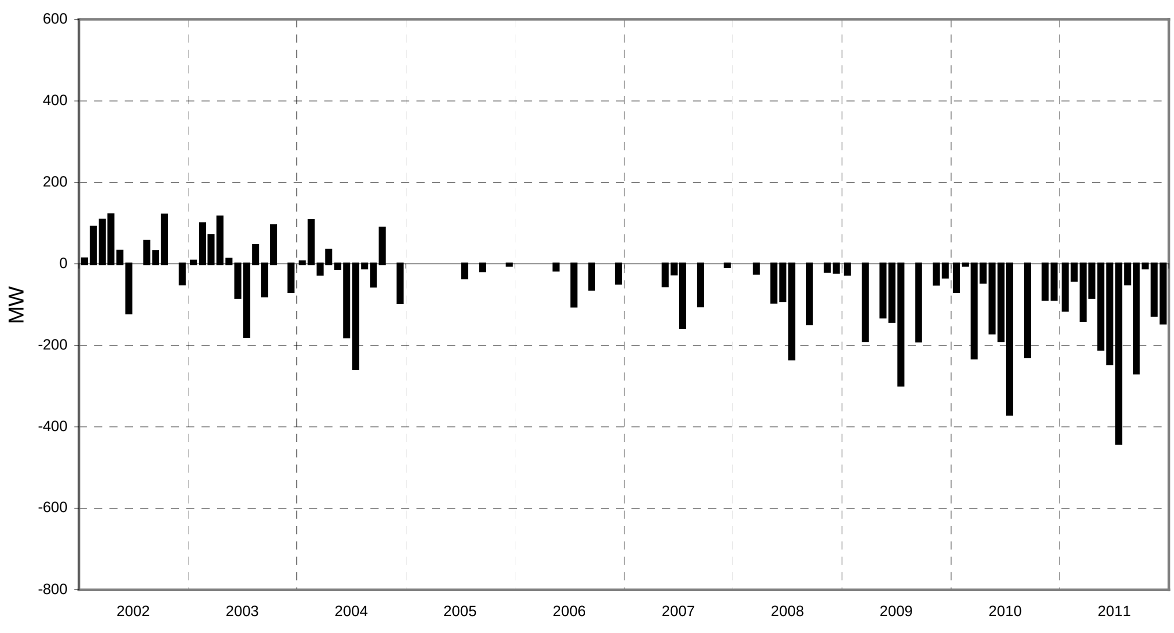


Figure 17 Monthly NW Transmission Deficit - 90th Percentile Water, 70th Percentile Load, Strategy 4 Resources with Garnet and Brownlee-Oxbow Transmission Upgrade

7. Near-Term Action Plan

Introduction

Customer growth is the primary driving force behind Idaho Power Company's need for additional resources. Population growth throughout Southern Idaho, and specifically in the Treasure Valley, requires additional measures to meet both peak and energy needs.

Over the past 85 years, Idaho Power Company has developed a portfolio of generation resources. IPC believes that a blended approach based on a portfolio of options is the most cost-effective and least-risk method to address the increasing energy demands of our customers.

Supply-side generation resources are likely to be the primary method to meet the increasing energy demands of Idaho Power Company customers. However, IPC customers have expressed an interest that all generation resources be financially, environmentally, and socially responsible.

Near-Term Action Plan

First, Idaho Power Company plans to continue to make seasonal market purchases of 100 aMW in the months of June, July, November and December throughout the planning period.

Second, Idaho Power Company plans to integrate demand-side measures where economically feasible, to address the short duration peaks of the system load.

Third, Idaho Power Company plans to solicit proposals and initiate the siting and permitting for approximately 100 MW of a utility owned and operated peaking resource to be available beginning in 2005.

Fourth, assuming the Idaho PUC approves the Garnet Power Purchase Agreement, Idaho Power will purchase up to 250 MW of capacity and associated energy during periods of peak need beginning June 1, 2005.

Fifth, Idaho Power Company plans to proceed with the Brownlee to Oxbow transmission line, expecting the project to be in service in 2005, increasing the import capabilities from the Pacific Northwest.

Sixth, Idaho Power Company plans to proceed with the Shoshone Falls upgrade project, expecting the upgrade to be in service in 2007.

Finally, Idaho Power Company plans to informally reassess the deficiencies that remain in 2008 though 2011 prior to 2004. The deficiencies will be formally assessed in the 2004 IRP.

Market Purchases

Idaho Power customers, the state legislature, and the IPUC have all recommended that Idaho Power Company rely less on the short-term regional power market to meet long-term energy deficiencies. IPC agrees with this assessment. However, the Company believes that participation in the short-term market produces distinct financial advantages for IPC customers. Therefore, IPC will continue to use the short-term regional market to balance the system load and generation, as well as to take advantage of the short-term market to secure low-cost energy at a reasonable risk as described in the Least-Cost Resource Plan.

Purchasing energy and capacity from the Pacific Northwest long-term market will continue to be the preferred source of supply for a portion of Idaho Power's incremental resource needs throughout the planning period. Idaho Power expects that, for the remainder of 2002 through 2004 under adverse water and load conditions, adequate transmission capability does not exist to allow all of the required purchases to be delivered to the Idaho Power system from the Pacific Northwest.

A combination of purchases from utilities to the northeast or southeast, targeted demand reduction measures, and temporary generation resources may be necessary to fulfill any remaining requirements. However, there is some degree of uncertainty regarding the availability of both generation and transmission from the utilities to the northeast and southeast.

Generation Resources

Population growth in Southern Idaho is an inescapable fact. IPC will need physical resources, such as the Evander Andrews Power Complex near Mountain Home, Idaho, to meet the energy demands of the additional customers. Idaho Power Company will continue to analyze resource additions and select resources that responsibly meet the needs of our customers.

Idaho Power will continue with cost-effective incremental efficiency upgrades to existing generation facilities, including possible turbine upgrades at the Boardman and Valmy plants and the Shoshone Falls upgrade.

In recognition of seasonal peak deficiencies and recognizing the limitations of the transmission system to allow the deficits to be covered solely by off-system purchases, Idaho Power will need to acquire additional peaking resources.

Idaho Power Company intends to initiate a request for proposals (RFP) to construct approximately 100 MW of simple-cycle combustion peaking capacity between the Brownlee East and Borah West transmission constraints. The RFP process ensures that the resource will be constructed at a competitive price for Idaho Power's customers.

An important aspect of the ongoing relicensing process for Idaho Power's hydroelectric facilities is identifying the present and future value of power generation from the relicensed facility. The integrated resource planning process will provide an ongoing basis and methodology to evaluate the IPC hydroelectric generating facilities for relicensing consistent with other resource options. Any proposed modifications or expansions of generating capacity at existing hydroelectric facilities, such as the Shoshone Falls upgrade, will be evaluated within the IRP methodology.

Transmission Resources

Idaho Power Company is currently pursuing the Brownlee to Oxbow transmission upgrade and expects to begin construction in 2004. The project has been identified as the most cost-effective alternative to expand transmission capacity and import electrical power from other generation sources through the interconnected transmission line grid in the Western United States.

The Brownlee to Oxbow project will increase the reliability of Idaho Power's transmission system, and increase the Brownlee East transmission capacity by approximately 100 MW. The expected service date is November 2004.

Demand-Side Management, Energy Conservation, and Pricing Options

Socially responsible conservation and energy efficiency means doing more with less, rather than doing without. Idaho Power Company will continue to support energy efficiency at our facilities and our customers' facilities. Idaho Power Company plans to continue active participation in regional conservation efforts.

Due to the nature and timing of the projected energy deficits and transmission overloads, conservation and demand-side measures must be carefully designed and targeted to cost-effectively address the projected peak deficits. Idaho Power Company anticipates the addition of targeted demand-side management, targeted pricing options, and targeted energy conservation programs.

Idaho Power will also proceed with plans to improve energy efficiency at company facilities, including office buildings, local offices, maintenance yards, small buildings, and power plants.

Green Energy

Idaho Power Company is supportive of the Green Power Program (Schedule 62). To meet the needs of customers desiring this product, Idaho Power plans to include additional green energy in the IPC generation portfolio. In addition, IPC has identified two specific near-term actions to be initiated during the next two years:

1. Idaho Power Company anticipates participating in educational and demonstrational energy projects with the focus on green resources.
2. Idaho Power intends to dedicate up to $50,000 to explore the feasibility of constructing a pilot anaerobic digester project within the IPC service territory.

In addition to the near-term actions, Idaho Power anticipates adding a utility scale (50 to 100 MW) wind project within its service territory. The exact timing, location, and size of the wind project will be determined by events listed below. Idaho Power anticipates using an RFP process to develop a wind project.

Because of the intermittent nature of wind generation, Idaho Power views wind generation primarily as an energy resource and not a peaking resource. Considering the seasonal and peak nature of Idaho Power's projected deficiencies, Idaho Power does not anticipate adding a wind project to address seasonal energy and capacity needs. However, the addition of a wind project could be triggered at any time by any of the following events:

1. Increased customer demand for green energy as measured through Idaho Power's existing Green Power Program. If Idaho Power customers' demand for Green Power increases to 15 aMW, then Idaho Power will initiate a RFP for a wind project sized to meet this need (a 50 MW project operating at a 30 percent capacity factor would provide 15 aMW).
2. Public Utility Commission or Legislative action (either unsolicited or in response to an Idaho Power proposal) for Idaho Power to add a wind project to its generation portfolio and regulatory approval to add the project into ratebase for cost recovery.
3. A change in Idaho Power's projected surplus/deficiency that indicates the need to add an energy resource.

Idaho Power Company and the Commissions must agree on mechanisms that ensure prompt recovery of prudent costs incurred for the pilot and demonstration projects.

Idaho Power Company continually works to improve its resource planning process and has recently made organizational changes to further improve integrated resource planning. Idaho Power Company agrees with the Idaho Public Utility Commission that integrated resource planning will continue to be an important and ongoing activity at Idaho Power Company.